SRI/USEPA-GHG-QAP-22
November 2002

# Test and Quality Assurance Plan

## Swine Waste Electric Power and Heat Production Systems:

### Capstone MicroTurbine™ and Martin Machinery Internal Combustion Engine

Prepared by:

**Greenhouse Gas Technology Center**
**Southern Research Institute**

Under a Cooperative Agreement With
U.S. Environmental Protection Agency

SRI/USEPA-GHG-QAP-22
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# Greenhouse Gas Technology Center

*A U.S. EPA Sponsored Environmental Technology Verification ( ETV ) Organization*

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☒ indicates comments are integrated into Test Plan

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This Test and Quality Assurance Plan has been reviewed and approved by the Greenhouse Gas Technology Center Project Manager and Center Director, the U.S. EPA APPCD Project Officer, and the U.S. EPA APPCD Quality Assurance Manager.

| | | | |
|---|---|---|---|
| Original signed by: | | Original signed by: | |
| ______________________ | _______ | ______________________ | _______ |
| Stephen Piccot<br>Center Director<br>Greenhouse Gas Technology Center<br>Southern Research Institute | Date | David Kirchgessner<br>APPCD Project Officer<br>U.S. EPA | Date |
| Original signed by: | | Original signed by: | |
| ______________________ | _______ | ______________________ | _______ |
| Sushma Masemore<br>Project Manager<br>Greenhouse Gas Technology Center<br>Southern Research Institute | Date | Shirley Wasson<br>APPCD Quality Assurance Manager<br>U.S. EPA | Date |

Test Plan Final: November 2002

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# 1.0 INTRODUCTION

## 1.1 BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of the ETV program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. Congress funds ETV in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The Greenhouse Gas Technology Center (GHG Center) is one of six verification organizations operating under the ETV program. The GHG Center is managed by EPA's partner verification organization, Southern Research Institute (SRI), which conducts verification testing of promising GHG mitigation and monitoring technologies. The GHG Center's verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, obtaining independent peer-review input, and reporting findings. Performance evaluations are conducted according to externally reviewed verification Test and Quality Assurance Plans (Test Plan) and established protocols for quality assurance (QA).

The GHG Center is guided by volunteer groups of stakeholders. These stakeholders offer advice on specific technologies most appropriate for testing, help disseminate results, and review Test Plans and Technology Verification Reports (Report). The GHG Center's Executive Stakeholder Group consists of national and international experts in the areas of climate science and environmental policy, technology, and regulation. It also includes industry trade organizations, environmental technology finance groups, governmental organizations, and other interested groups. The GHG Center's activities are also guided by industry specific stakeholders who provide guidance on the verification testing strategy related to their area of expertise and peer-review key documents prepared by the GHG Center.

One technology of interest to some GHG Center's stakeholders is distributed electrical power generation systems. Distributed generation (DG) refers to equipment, typically ranging from 5 to 1,000 kilowatts (kW) that provide electric power at a site closer to customers than central station generation. A distributed power unit can be connected directly to the customer or to a utility's transmission and distribution system. Examples of technologies available for DG includes gas turbine generators, internal combustion engine generators (gas, diesel, other), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: standby generation (i.e., emergency backup power), peak shaving generation (during high demand periods), baseload generation (constant generation), or cogeneration (combined heat and power generation).

Recently, biogas production from livestock manure management facilities has become a good alternative to fueling DG technologies. EPA estimates U.S. methane emissions from livestock manure management at 17.0 million tons carbon equivalent, which accounts for 10 percent of total 1997 methane emissions (EPA 1999a). The majority of methane emissions come from large swine (hog) and dairy farms that manage manure as a liquid. EPA expects U.S. methane emissions from livestock manure to grow by over 25 percent from 2000 to 2020. Cost effective technologies are available that can stem this emission growth by recovering methane and using it as an energy source. These technologies commonly referred to as anaerobic digesters, decompose manure in a controlled environment and recover methane produced from the manure. The recovered methane can fuel power generators to produce electricity, heat, and hot water. Digesters also reduce foul odor and can reduce the risk of ground- and surface-water pollution.

The GHG Center and the Colorado Governors Office of Energy Management and Conservation (OEMC) have agreed to collaborate and share the cost of verifying two DG technologies that operate on biogas recovered from swine waste. This verification will evaluate the performance of a microturbine combined heat and power (CHP) system offered by Capstone Turbine Corporation and an internal combustion (IC) engine CHP system offered by Martin Machinery, Inc. Both units are currently in operation at an anaerobic digestion facility managed by Colorado Pork, LLC near Lamar, Colorado. This is the only swine farm in Colorado that is producing electrical power from animal waste. The electricity is used by Colorado Pork to offset electricity purchases from the local electric cooperative. Some of the recovered heat is used to control digester temperature, which optimizes and enhances biogas production. Both CHP systems are interconnected to the electric utility grid, but excess power is not presently exported. The OEMC team is currently under negotiations with the local utility to export power for sale.

The GHG Center will evaluate the performance of the microturbine and the IC engine CHP systems as they run off the same biogas stream at Colorado Pork. Field tests will be executed over a 2 to 3 week period to independently verify the electricity generation rate, thermal energy recovery rate, energy efficiency, environmental emissions, electrical power quality, and emission reductions associated with CHP electricity generation.

This document is the Test Plan for performance verification of the two CHP systems at Colorado Pork. It contains the rationale for the selection of verification parameters, the verification approach, data quality objectives (DQOs), and Quality Assurance/Quality Control procedures (QA/QC), and will guide implementation of the test, creation of test documentation, data analysis, and interpretation.

This Test Plan has been reviewed by the OEMC team which includes OEMC, Colorado Pork, and McNeil Technologies, selected members of the GHG Center's DG Technical Panel, and the U.S. EPA QA team. Once approved, as evidenced by the signature sheet at the front of this document, it will meet the requirements of the GHG Center's Quality Management Plan (QMP) and thereby satisfy the ETV QMP requirements. The final Test Plan will be posted on the Web sites maintained by the GHG Center (www.sri-rtp.com) and the ETV program (www.epa.gov/etv).

Upon field test completion, the GHG Center will prepare a separate Report and Verification Statement for each system tested. The Report will be reviewed by the same organizations listed above, followed by EPA-ORD technical review. When this review is complete, the GHG Center Director and EPA-ORD Laboratory Director will sign the Verification Statement, and the final documents will be posted on the GHG Center and ETV program Web sites.

The following section provides a description of the microturbine and IC engine technology. This is followed by a list of performance verification parameters that will be quantified through independent testing at the site. The section concludes with a discussion of key organizations participating in this verification, their roles, and the verification test schedule. Section 2.0 describes the technical approach for verifying each parameter, including sampling, analytical, and QA/QC procedures. Section 3.0 identifies the data quality assessment criteria for critical measurements and states the accuracy, precision, and completeness goals for each measurement. Section 4.0 discusses data acquisition, validation, reporting, and auditing procedures.

## 1.2 CAPSTONE MICROTURBINE TECHNOLOGY DESCRIPTION

Natural-gas-fired turbines have been used to generate electricity since the 1950s. Technical and manufacturing developments in the last decade have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW. Microturbines have evolved from automotive and truck turbocharger technology and small jet engine technology. Most microturbines consist of a compressor, combustor, recuperator, and generator. They have a small number of moving parts, and their compact size enables them to be located on sites with limited space. For sites with thermal demands, a waste heat recovery system can be integrated with a microturbine to achieve higher efficiencies.

Although natural gas has been the primary choice of fuel for most applications, operators are increasingly examining the applicability of this technology on biogas recovered from animal waste, landfills, and wastewater treatment facilities. The availability of "free" fuel in the agricultural sector, particularly for swine and dairy operations, may offer a cost effective means of meeting odor regulations while simultaneously generating electricity and heat to offset a site's energy demand. Microturbines operating on biogas require a dryer system, which knocks out excess moisture, and a booster compressor, which pressurizes the low-pressure biogas to meet the turbine fuel pressure requirements.

The microturbine system to be verified at Colorado Pork is illustrated in Figure 1-1. It consists of a Capstone MicroTurbine™ Model 330 (developed by Capstone Turbine Corporation), a heat recovery system (developed by Unifin International), a booster compressor (developed by Copeland Corporation), and a desiccant dryer (developed by Van Air Systems, Inc.). The entire packaged system for biogas application was purchased from Capstone Turbine Corporation. The host site is currently undergoing preliminary tests to determine if the Copeland Compressor is suitable for their biogas applications. In the event another unit replaces this compressor, the process description will be revised accordingly. The change in the compressor is not expected to significantly affect the verification testing approach. Figure 1-2 illustrates a simplified process flow diagram of the microturbine CHP system, and a discussion of each component is provided below.

**Figure 1-1. Colorado Pork Microturbine System**

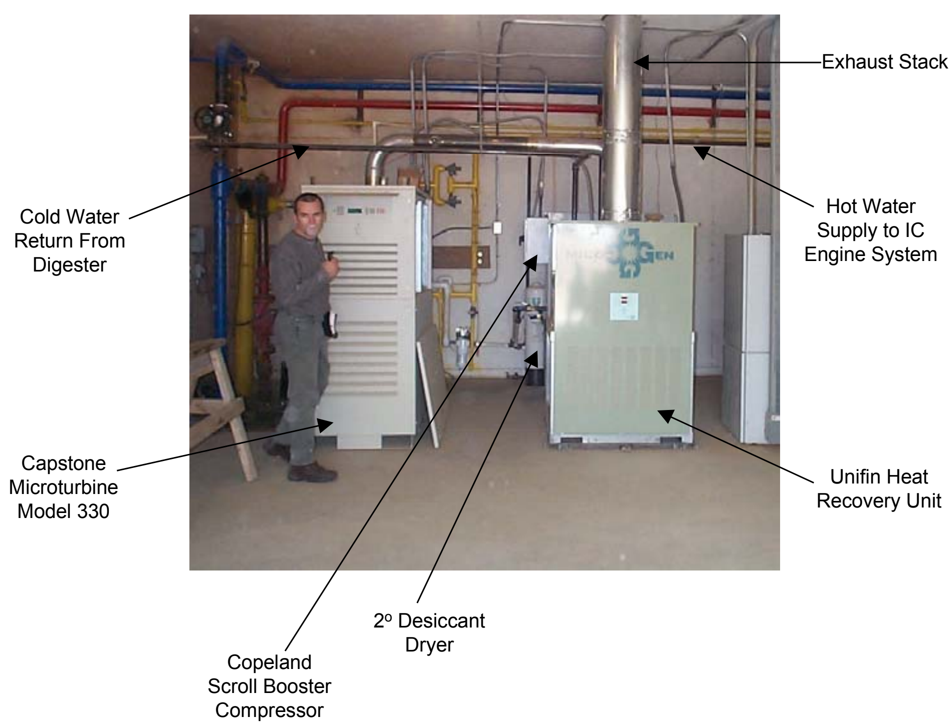
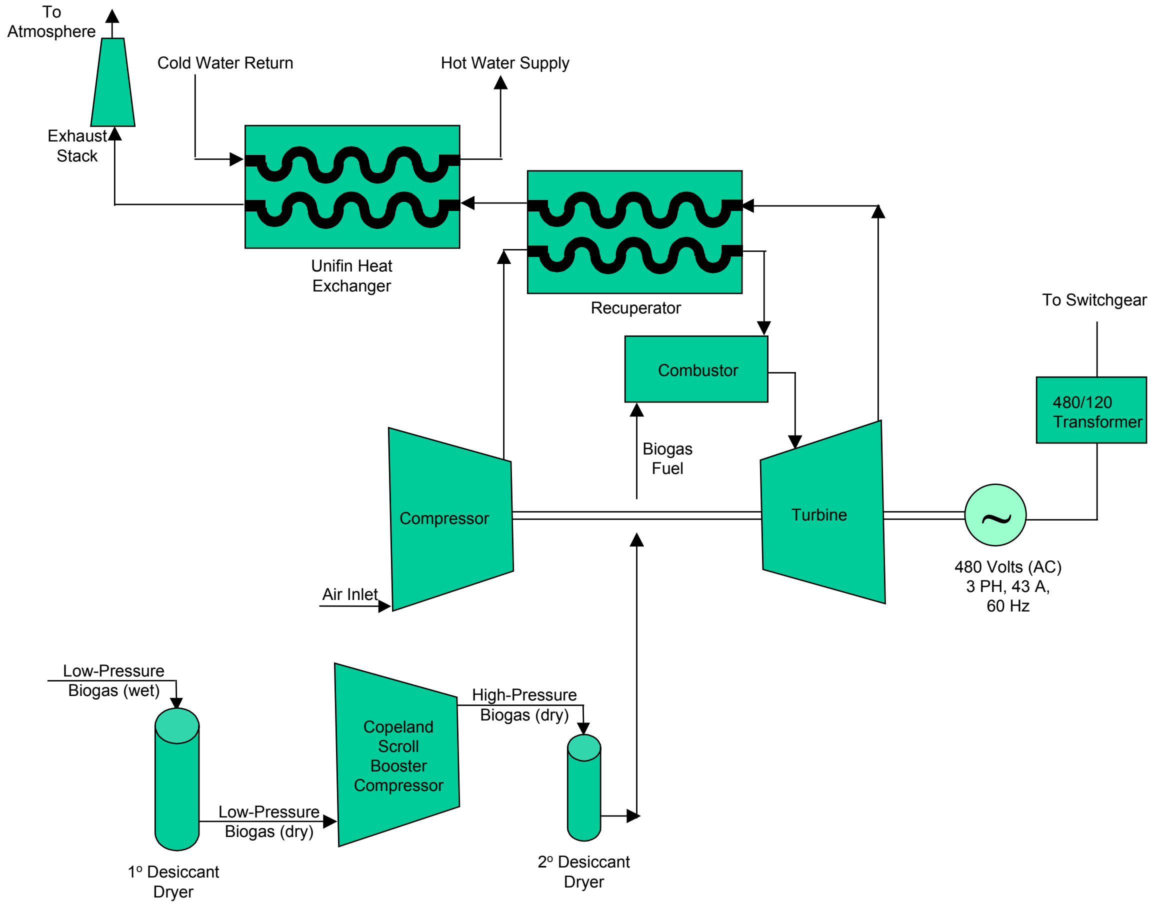


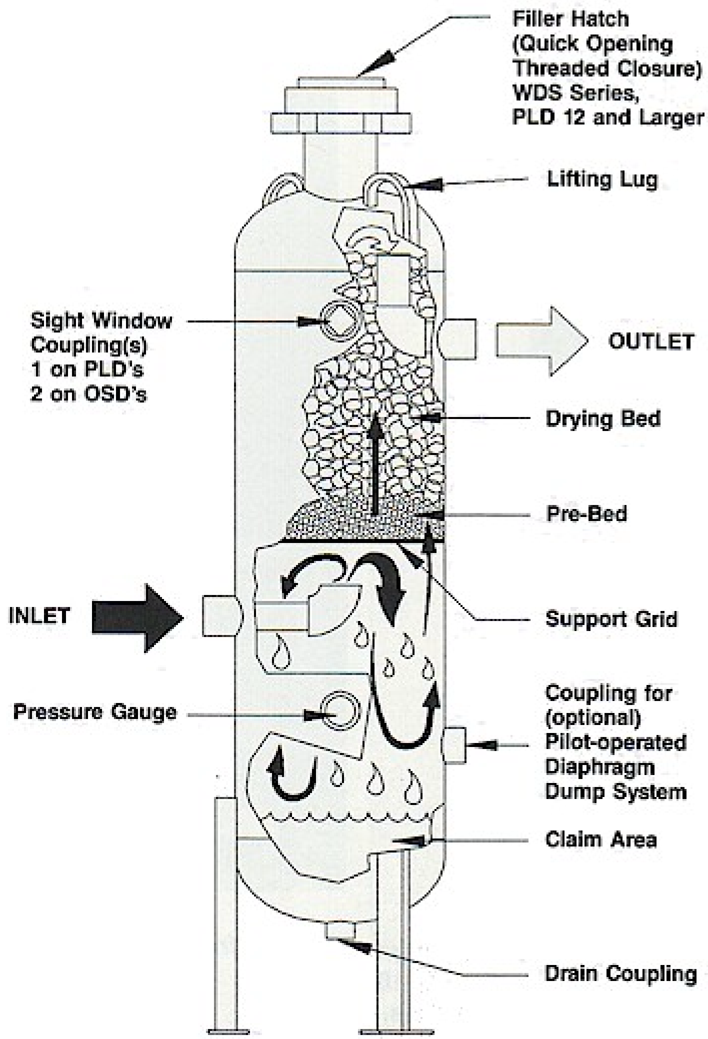
**Figure 1-2. Capstone Microturbine System Process Diagram**




Biogas produced from the anaerobic digester is saturated with moisture, which must be removed prior to operating the microturbine system. For such applications, Capstone requires installation of a desiccant dryer(s), manufactured by Van Air Systems, Inc. Figure 1-3 illustrates a single tower desiccant dryer. Wet biogas enters the centrally located inlet port in the lower portion of the vessel where the gas velocity is reduced. In this area, heavier drops of entrained water are separated and fall into a large-capacity claim area. As the biogas moves upward through the bed of drying tablets, water vapor is absorbed on the surface of the tablets. The water and drying material combine into a solution that falls into the claim area. Dry biogas, free of liquid waste and water vapor, exits from the dryer outlet.

At the test site elevation (approximately 3,615 feet), an average biogas production rate of 21,000 cubic feet per day (cfd) is expected. At 100 $^{o}$F, 17 inches water fuel pressure, and approximately 12.916 psia atmospheric pressure, the biogas saturated with water vapor is estimated to contain about 7 percent (volume basis) moisture content. This is equivalent to about 2,837 pounds of water per million cubic feet gas (lb/MMcf). The desiccant dryer, shown in Figures 1-2 and 1-3, is designed to achieve less than one volume percent water content or 405 lb/MMcf (a reduction of about 86 percent).

**Figure 1-3. Desiccant Dryer for Microturbine System**
(Source: Van Air Systems, Inc.)


Capstone requires an external booster compressor, manufactured by Copeland Corporation, to pressurize the biogas to about 55 pounds per square inch gauge (psig). The booster compressor is a variable flow scroll compressor with a design life of 20,000 hours. Its hermetic design is reported to eliminate shaft seal leaks, and offers quiet operation. It pressurizes gas as low as 0.5 psig, and consumes about 2.6 kW electric power. Table 1-1 summarizes key operational and performance characteristics reported by Capstone and Copeland.

| Table 1-1. Copeland Booster Compressor Specifications [a] (Source: Capstone Microturbine Corporation, Copeland Corporation) | | |
|---|---|---|
| Dimensions | Width<br>Length<br>Height | 24 in.<br>46 in.<br>42 in. |
| Weight | | 550 lb |
| Noise Level | Typical reported by Capstone | 55 dBA @ 10 m |
| Operating Parameters | Minimum Inlet Pressure<br>Maximum Outlet Pressure | 0.5 psig<br>100 psig |
| | Maximum Inlet Temperature<br>Maximum Outlet Temperature | 120 $^oF$<br>150 $^oF$ |
| | Ambient Temperature Range | 14 to 120 $^oF$ |
| | Gas Volume | 0 to 29 scfm<br>0 to 79 lb/hr |
| | Power Consumption<br>(0.5 to 15 psig inlet pressure) | 2.4 to 2.6 kVA |
| Inlet Gas Requirements | Hydrogen Sulfide ($H_2S$) Concentration<br>Water Concentration<br>Carbon Dioxide ($CO_2$) Concentration | < 45 ppm<br>TBD<br>< 2.5 % |
| Service | Every 8,000 hours | Top up oil level<br>Clean air intake/exhaust screens<br>Replace inlet filter<br>Replace oil separator |

[a] These specifications are for pipeline quality natural gas

As shown in Figure 1-2, pressurized biogas exiting the booster compressor is further dehydrated with a secondary ($2^o$) desiccant dryer. This is to ensure the water content of biogas fuel into the microturbine is minimized. The $2^o$ desiccant dryer is expected to remove an additional 87 percent of water content.

Electric power is generated from a high-speed, single shaft, recuperated turbine generator with a nominal power output of 30 kW (59 $^oF$, sea level). Table 1-2 summarizes the physical and electrical specifications for a Capstone Model 330 microturbine. It is designed to operate on medium-quality biogas, and consists of an air compressor, recuperator, combustor, turbine, and a permanent magnet generator. The recuperator is a heat exchanger that recovers some of the heat from the exhaust stream and transfers it to the incoming compressed air stream. The preheated air is then mixed with the fuel, and this compressed fuel/air mixture is burned in the combustor under constant pressure conditions. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine blades to turn a generator, which produces electricity. Because of the inverter-based electronics that enable the generator to operate at high speeds and frequencies, the need for a gearbox and associated moving parts is eliminated. The rotating components are mounted on a single shaft, supported by patented air bearings that rotate at over 96,000 revolutions per minute (rpm) at full load. The exhaust gas exits the turbine and enters the recuperator, which pre-heats the air entering the combustor, to improve the efficiency of the system. The exhaust gas then exits the recuperator into a Unifin heat recovery unit.

The permanent magnet generator produces high frequency alternating current, which is rectified, inverted, and filtered by the line power unit into conditioned 480 volts alternating current (VAC). A transformer steps this down to 120 volts for use at the host facility. The unit supplies a variable electrical frequency of 50 or 60 hertz (Hz), and is supplied with a control system, which allows for automatic and unattended operation. An active filter in the generator's power conditioner is reported by the turbine manufacturer to provide cleaner power, free of spikes and unwanted harmonics. All operations, including startup, setting of programmable interlocks, grid synchronization, operational setting, dispatch, and shutdown, can be performed manually or remotely using an internal power controller system.

**Table 1-2. Capstone Microturbine Model 330 Specifications**
(Source: Capstone Microturbine Corporation, Colorado Pork)

| | | |
|---|---|---|
| Dimensions | Width<br>Depth<br>Height | 28.1 in.<br>52.9 in.<br>74.8 in. |
| Weight | Microturbine only | 1,052 lb |
| Electrical Inputs | Power (startup)<br>Communications | Utility Grid or Black Start Battery<br>Ethernet IP or Modem |
| Electrical Outputs | Power at ISO Conditions 59 $^{o}$F @ sea level) | 30 kW, 400-480 VAC,<br>50/60 Hz, 3-phase |
| Noise Level | Typical reported by Capstone | 58 dBA at 33 ft |
| Fuel Pressure Required | w/o Natural Gas Compressor<br>w/ Natural Gas Compressor | 52 to 55 psig<br>5 to 15 psig |
| Fuel Heat Content | Higher Heating Value | 350 to 1,200 Btu/scf |
| Electrical Performance at Full Load (landfill or digester gas) | Heat Input<br>Power Output<br>Efficiency - w/o Natural Gas Compressor<br>Efficiency - w/ Natural Gas Compressor<br>Heat Rate | 378,000 Btu/hr, LHV basis<br>30 kW ±1 kW<br>27 % ±2 %, ISO conditions, LHV basis<br>26 % ±2 %, ISO conditions, LHV basis<br>12,600 Btu/kWh, LHV basis |
| Heat Recovery Potential at Full Load | Exhaust Gas Temperature<br>Exhaust Energy Available for Heat Recovery | 500 $^{o}$F<br>290,000 Btu/hr |
| Emissions (full load) | Nitrogen oxides ($NO_X$)<br>Carbon monoxide (CO)<br>Total hydrocarbon (THCs) | < 9 ppmv @ 15 % $O_2$<br>< 40 ppmv @ 15 % $O_2$<br>< 9 ppmv @ 15 % $O_2$ |

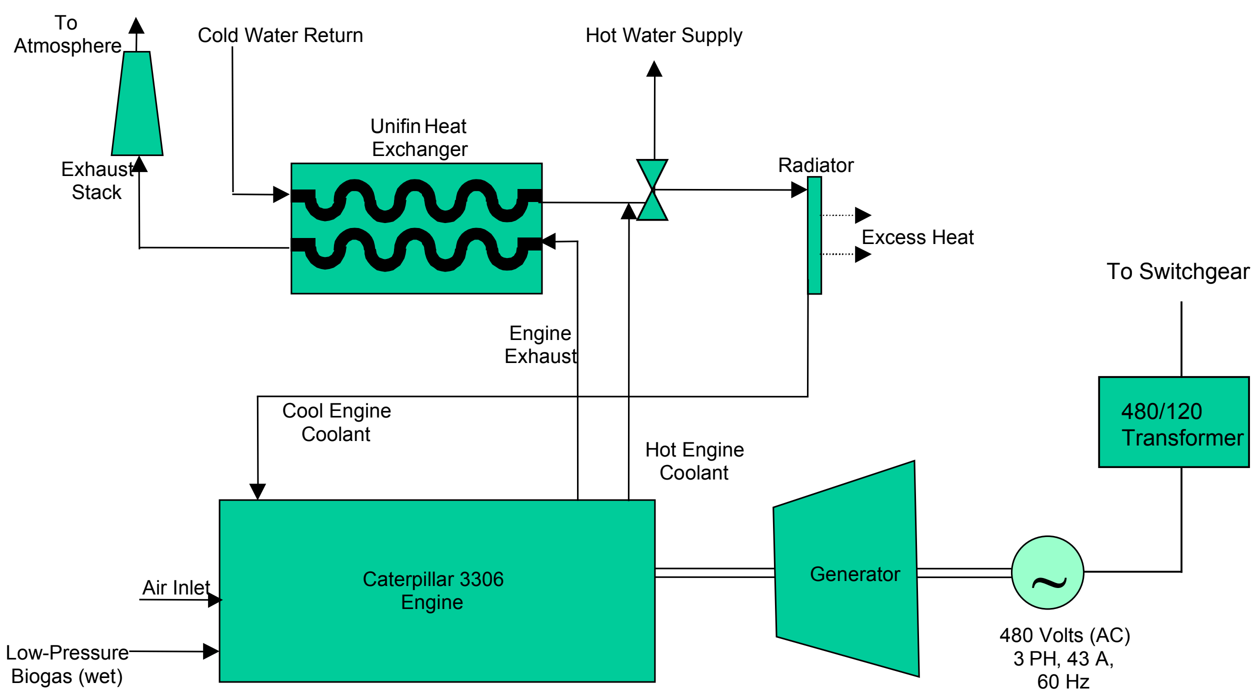
As shown in Figure 1-2, waste heat from the microturbine is recovered using a heat recovery and control system developed by Unifin International, and integrated by Capstone. It is an aluminum fin and tube heat exchanger suitable for up to 700 °F exhaust gas. Potable water is used as the heat transfer media to recover energy from the microturbine exhaust gas stream. A digital controller monitors the water outlet temperature, and when the temperature exceeds user set point, an "exhaust gas divertor" automatically closes and allows the hot gas to bypass the heat exchanger and release the heat through the stack. When heat recovery is required (i.e., water outlet temperature is less than user setpoint), the flap allows hot gas to circulate through the heat exchanger. This design allows the system to protect the heat recovery components from the full heat of the turbine exhaust, while still maintaining full electrical generation from the microturbine.

## 1.3 MARTIN MACHINERY IC ENGINE TECHNOLOGY DESCRIPTION

The Colorado Pork facility uses an IC engine fired with digester gas to generate electricity and thermal energy. This system, designed and built by Martin Machinery, is one of the first cogeneration installations in the country that generates both electrical and thermal energy using digester gas for fuel. The CHP system (Figure 1-4) includes an IC engine, an electric generator, and a heat exchanger. Figure 1-5 illustrates a simplified process flow diagram of the CHP system, and a discussion of key components is provided.

**Figure 1-4. Colorado Pork IC Engine CHP System**


**Figure 1-5. Martin Machinery CHP Process Diagram**



Power is generated with a Caterpillar (Model 3306 ST) IC engine, with a nominal power output of 100 kW (60 $^{o}$F, sea level). Table 1-3 summarizes the specifications reported by Martin Machinery for this engine/generator set. Additional performance characteristics, as reported by Martin Machinery, are included in the technical data sheet in Appendix C-1. The IC engine is a 6 cylinder, 4-stroke, naturally aspirated unit with a 10.5:1 compression ratio and a speed range of 1,000 to 1,800 rpm. The IC engine is used to drive an induction generator manufactured by Marathon Electric (Model No. MCTG-80-3).

The generator produces 480 VAC. The unit supplies a constant electrical frequency of 60 Hz, and is supplied with a control system that allows for automatic and unattended operation. All operations, including startup, operational setting (kW command), dispatch, and shutdown, are performed manually.

Biogas production rates at the test site limit engine operation to approximately 65 kW, or about 65 percent capacity. Electricity generated at this load is fully consumed by equipment used at the facility. During normal farm operations, power demand exceeds the available capacity of the engine/generator set, and additional power is drawn from the grid. On rare occasions when the power generated exceeds farm demand, a reverse power relay (required by the utility company) throttles down the engine. Currently, the local utility does not permit power to be exported to the grid. In the event of a grid power failure, the facility has a backup emergency generator to provide additional power.

No digester gas conditioning or compression is needed to operate the engine under these conditions. Digester gas is directed to the engine and fired at the pressure created in the digester (approximately 17 to 18 inches water column). Because the digester gas is not conditioned (e.g., moisture and sulfur removal), engine lubrication oil is changed every 10 days as precautionary maintenance.

**Table 1-3. Martin Machinery CHP Physical, Electrical, and Thermal Specifications**
(Source: Colorado Pork, Martin Machinery)

| | | |
|---|---|---|
| Weight | Engine only | 2,090 lb |
| Engine Speed | | 1,800 rpm |
| Electrical Inputs | Power (startup) | Utility Grid or Backup Generator |
| Electrical Outputs | Power at ISO Conditions 60 $^{o}$F (@ sea level) for electric | 100 kW, 120 VAC,<br>60 Hz, 3-phase |
| Fuel Pressure Required | w/o Natural Gas Compressor | 2 to 20 psi, nominal |
| Fuel Input | Heat Input | 1,133,060 Btu/hr @ 100 kW<br>905,000 Btu/hr @ 75 kW<br>~ 820,292 Btu/hr @ 65 kW<br>693,230 Btu/hr @ 50 kW |
| | Flow Rate (LHV = 905 Btu/ft$^3$) | 1,252 scfh @ 100 kW<br>1,000 scfh @ 75 kW<br>766 scfh @ 50 kW |
| Electrical Efficiency, Lower Heating Value (LHV) basis | With Natural Gas (ISO Conditions) | 30 % @ 100 kW<br>28 % @ 75 kW<br>25 % @ 50 kW |
| Heat Rate | At Full Load | 11,331 Btu/kWh |
| Heat Recovery Potential | Exhaust Gas Temperature<br>Exhaust Energy Available for Heat Recovery | 1,100 $^{o}$F<br>508,980 Btu/hr @ 100 kW<br>311,954 Btu/hr @ 50 kW |

The engine is equipped with a Thermal Finned Tube (Model 12-12-60CEN-W) heat exchanger for heat recovery. The heat recovery system consists of a fin-and-tube heat exchanger, which circulates water through the heat exchanger at approximately 20 gallons per minute (gpm). The engine exhaust, at approximately 1,100 °F, is the primary source of heat to the exchanger. The engine cooling water is also cycled through the heat exchanger to recover additional heat and provide engine cooling. Circulation of engine coolant is thermostatically controlled to maintain coolant temperature at approximately 175 °F. In the event temperatures exceed 185 °F, excess heat is discarded with the use of an external radiator. The radiator's return water line serves as the coolant for the engine water jacket.

## 1.4 TEST FACILITY DESCRIPTION

Colorado Pork began the sow farrow-to-wean operation in 1999. The facility employs a complete mix anaerobic digester (Figure 1-6) to reduce odor and meet water quality regulations mandated by the Colorado Department of Public Health and Environment. The anaerobic digester promotes bacterial decomposition of volatile solids in animal wastes. The resulting effluent stream consists of mostly water, which is allowed to evaporate from a secondary lagoon.

**Figure 1-6. Colorado Pork Anaerobic Digester**

Waste from 5,000 sows is collected in shallow pits below the slatted floors of the hog barns. These pits are connected via sewer lines to an in-ground concrete holding tank (50,000 gallon capacity). Each morning, the pits are drained on a rotating basis to flush 12,500 gallons of waste to the holding tank. The holding tank is equipped with 1-17 horsepower (Hp) chopper pump that breaks up large pieces of waste. Before emptying the pits each morning at about 5:00 a.m., 12,500 gallons of waste is pumped from the holding tank into the digester (requires approximately 20 minutes).

The digester is a 70 x 80 x 14 feet deep in-ground concrete tank with a capacity of 500,000 gallons. The digester is equipped with two propeller type mixers on each end. The mixers normally operate for 30 minutes, daily in the evening to rejuvenate gas produced that would otherwise decline between feedings.

Hot water is circulated through the digester using a matrix of 3-inch black steel pipe (total length of about 0.5 mile) to maintain the digester temperature at 105 °F. Small adjustments to the water flow rate are required periodically and are conducted manually by the site operator. The retention time in the digester is about 40 days.

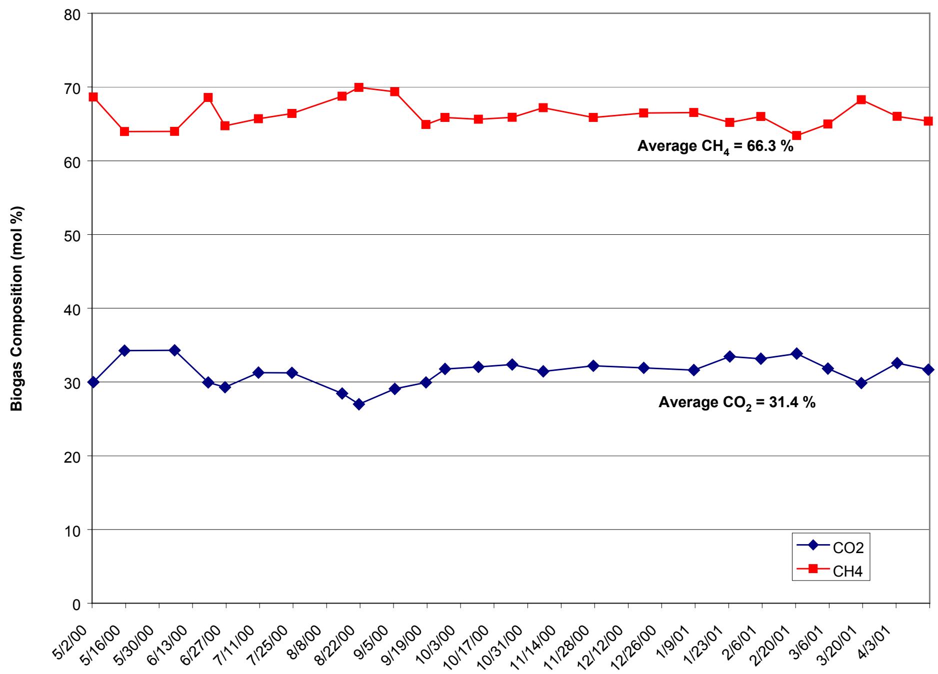
The effluent exits the digester over a weir, and is directed gravimetrically to a lagoon for sludge settling and water evaporation. The lagoon is designed to hold up to 20 years of sludge production. Tests performed by environmental regulatory personnel have determined the site meets current odor and discharge requirements.

The biogas produced from the decomposed waste is collected under a high-density polyethylene (HDPE) cover at a pressure of 17 to 18 inches water column. A manifold collects the biogas and routes it to the engine/turbine building. A pressure relief valve senses pressure buildup when neither the engine or turbine are operating, and diverts the biogas to a flare. Approximately 646,000 cubic feet of gas per month, (cfm) or an average daily production of 21,253 cfd is produced. This is based on monthly data collected by McNeil Technologies between May 2000 to April 2001. The variability in biogas production rate was ± 25 percent of the average value.

Figure 1-7 illustrates biogas composition over a 1-year sampling period. The gas samples were collected between 8:00 and 9:00 a.m. by Colorado Pork, approximately 2 times each month. The samples were shipped to an analytical laboratory in Lamar, Colorado, where gas compositional analysis was performed according to the American Society for Testing and Materials (ASTM) Method D1945. As shown in Figure 1-7, methane ($CH_4$) is the primary constituent, with an average composition of 66.3 percent. $CO_2$ represents an average of about 31.4 percent; together these gas species account for almost 98 percent of the biogas. The remaining constituents (< 2 percent) are nitrogen ($N_2$), oxygen ($O_2$), and trace amounts of $H_2S$. The concentration of total sulfur compounds is about 1,900 to 6,000 parts per million (ppm), of which more than 98 percent is $H_2S$.

Biogas composition is not expected to vary significantly in a year. The variability in $CH_4$ concentration was ± 0.7 percent (absolute). The stability in biogas composition was also observed at shorter time intervals (Table 1-4). During a recent pre-test survey, the GHG Center collected four biogas samples, spanning between 10 and 40 minutes. The $CH_4$ and $CO_2$ concentration values during these shorter sampling intervals are consistent with the bimonthly compositional data.

**Figure 1-7. Biogas Composition**




Due to the stability in biogas composition, significant variability in biogas heat content is not observed (Figure 1-8). On average, the higher heating value (HHV) of bimonthly measurement data was 673.1 ± 7.4 British thermal units per cubit foot (Btu/cf) (95 percent confidence interval). The data for shorter time increments is also within this range (Table 1-4). These data indicate that the heating value of fuel available for on-site electrical production is relatively consistent at Colorado Pork.

**Table 1-4. Pre-Test Gas Composition Results**
(Sampled 4/10/02)

| | Biogas Constituents (mole %) | | | | | Physical Properties | | Heating Value (Btu/cf) | |
|---|---|---|---|---|---|---|---|---|---|
| Time Collected (24-hr) | $CH_4$ | $CO_2$ | $N_2$ | $C_2$-$C_6$ Compounds | $H_2S$ | Relative Density | Compressibility | HHV | LHV |
| 1425 | 66.59 | 33.15 | 0.07 | < 0.01 | 0.19 | 0.8875 | 0.9970 | 675.7 | 608.4 |
| 1435 | 64.75 | 31.97 | 3.27 | < 0.01 | NA | 0.8781 | 0.9972 | 655.8 | 590.5 |
| 1455 | 64.76 | 31.7 | 3.22 | < 0.01 | NA | 0.8771 | 0.9972 | 656.0 | 590.7 |
| 1505 | 66.57 | 32.99 | 0.44 | < 0.01 | NA | 0.8763 | 0.9971 | 674.2 | 607.1 |
| | | | | | | | | | |
| Average | 65.67 | 32.45 | 1.75 | < 0.01 | 0.19 | 0.8798 | 0.9971 | 665.4 | 599.2 |

**Figure 1-8. Biogas Heat Content**

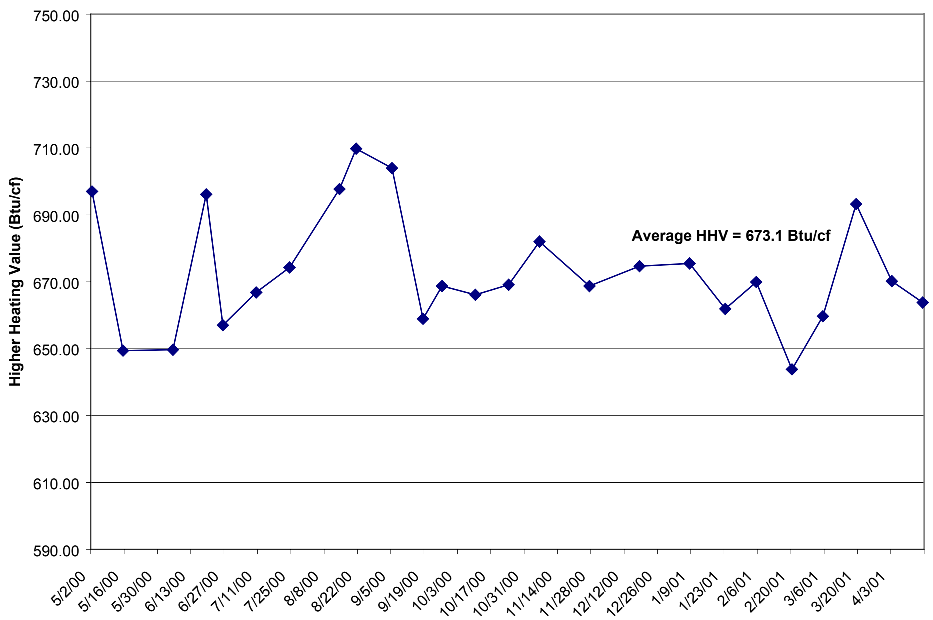
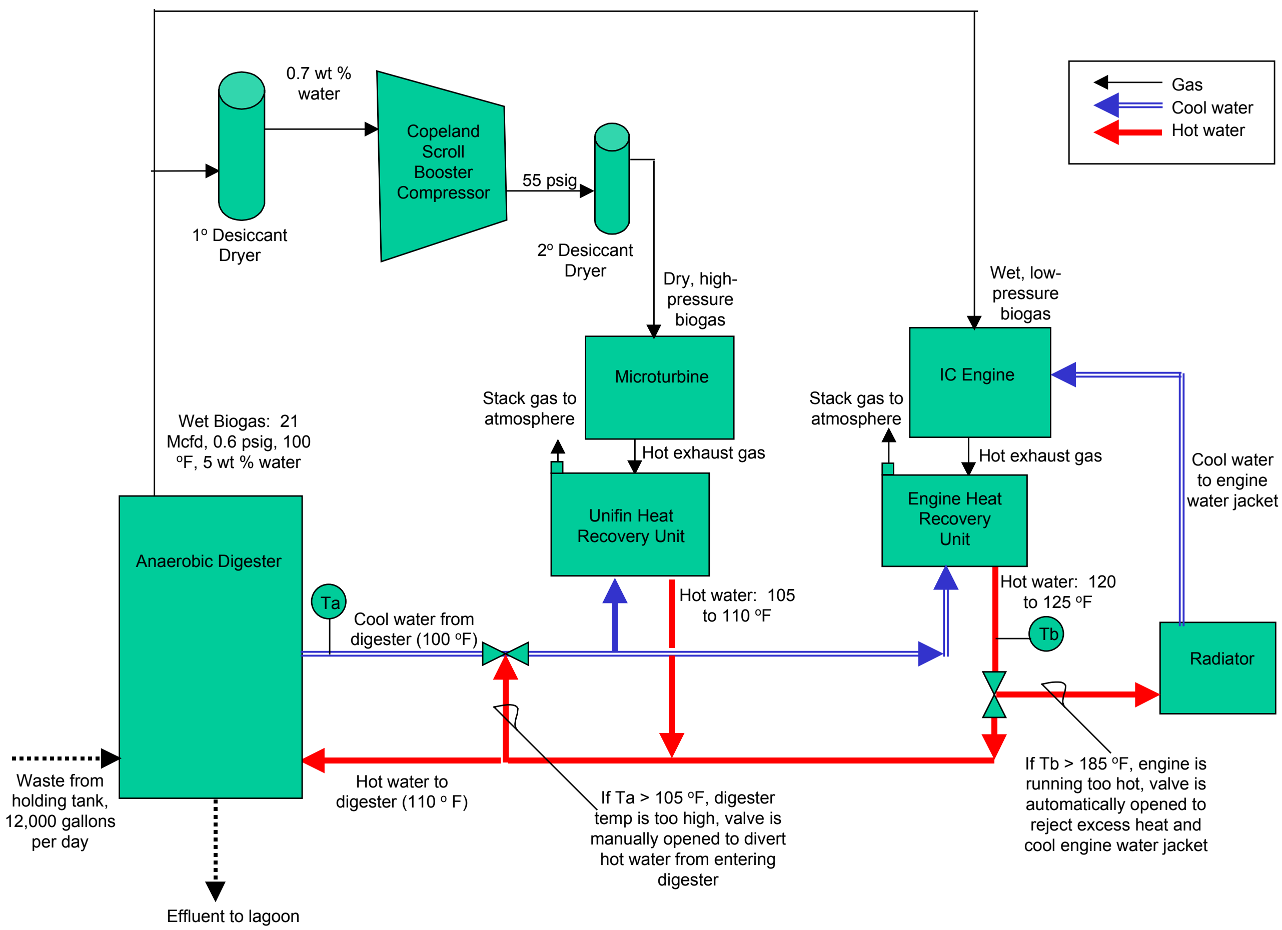



Figure 1-9 illustrates a schematic of the waste-to-energy production process at Colorado Pork. In May 2000, the IC engine CHP system was installed first to offset electricity purchase costs. The microturbine CHP system was installed in February 2002, to evaluate the feasibility and economics of the two different power generation technologies. Both systems are currently housed in a building adjacent to the digester.

With the microturbine CHP system, the biogas is treated and compressed to produce high-pressure, dry biogas for electricity production. The site operator sets the Unifin heat recovery unit at 110 °F during normal operations. Any unused heat is discarded automatically through the exhaust stack. With the IC engine CHP system, biogas is not pre-treated. The IC engine's heat recovery system produces hot water at approximately 125 °F. In the event this temperature exceeds 185 °F (i.e., during extremely hot summer days), an automatic valve is activated, which discards some of the excess heat through a radiator located outside the building. The radiator's return water line is used to cool the engine water jacket and prevent overheating the engine.

The IC engine hot water line combines with the microturbine hot water line, and the mixture is circulated through the waste in the digester to maintain the digester temperature at 105 °F. Cool water returning from the digester remains relatively constant throughout the year (approximately 100 °F). A temperature sensor continuously monitors this temperature, and in the event this temperature exceeds 105 °F, the site operator opens a manual valve, which reduces the flow of hot water entering the digester. This adjustment is performed only a few times per year, as digester temperatures remain relatively stable.

**Figure 1-9. Colorado Pork Waste-to-Energy Process Diagram**




Based on the estimated 21,000 cfd, biogas production capacity (± 25 percent), and a LHV of 673.1 Btu/cf, it is estimated that enough fuel is available to generate between 40 and 65 kW of electric power. Actual electricity load of the facility is much greater, approximately 100 to 196 kW. Colorado Pork has the means to generate additional biogas (e.g., obtain waste from other nearby operations) to reduce electricity purchases, if economics warrant additional on-site power generation. Appendix B contains a brief discussion of electrical loads and monthly electricity consumption data for the site.

To maximize the use of available biogas, the site plans to operate the microturbine at full load (30 kW nominal), and the IC engine at a minimum of 35 kW. When power demand of the farm operations exceed the available capacity of the power generation systems, power is drawn from the utility grid. Colorado Pork purchases electricity from the Southeast Colorado Power Association, a rural electric cooperative. On rare occasions, when the power generated exceeds farm demand, a reverse power relay (required by the utility) throttles down engine and/or microturbine power output. Under the current agreements with the utility, unused power is not permitted to be exported to the grid. The site is currently in negotiations with the local utility to enable power to be exported.

Colorado Pork purchases natural gas from a nearby natural gas wellhead operated by Lamar Oil and Natural Gas Exploration Company. Space and water heating are the two major natural gas users.

Appendix B contains a brief discussion of thermal loads and monthly natural gas consumption data for the site. Domestic hot water heaters at the site consume a relatively constant volume of natural gas [56 Mcf per month or 66,000 British thermal units per hour (Btu/hr)]. During winter months, colder temperatures result in a significant increase in natural gas consumption for space heating use (400 Mcf per month or 852,000 Btu/hr). This thermal energy demand is in addition to that required to heat the digester.

If sufficient digester gas is available to operate the microturbine and IC engine at 30 and 65 kW, respectively, a maximum of 599,000 Btu/hr could be recovered with an assumed thermal efficiency of 50 percent. This suggests that the on-site generation systems can offset all natural gas consumed for hot water heating, and about 25 percent of space heating requirements.

Although the IC engine will be operating well below its maximum capacity (100 kW), future increases in biogas production rates and potential agreement with the local utility to purchase excess power may result in higher electrical power to be generated from the systems at Colorado Pork. Consequently, additional demand for thermal energy for space heating and domestic hot water usage can be met.

## 1.5 PERFORMANCE VERIFICATION PARAMETERS

The verification test is scheduled to take place during the Fall of 2002. The primary objective of the test is to verify each CHP system's power and heat production performance, electrical power quality, and emissions performance. The approach selected for testing is intended to evaluate the performance of the CHP systems only, and not the specific operational or management strategy of the test facility.

It should be noted that by the time the verification test in initiated, the engine will be 3 years old and the microturbine will be 1 year old. It is possible that the engine's performance could decrease as it ages. However, consistent with ETV program operating principles, the results for each technology will be reported individually in two separate documents. As such, the GHG Center will not perform comparative analysis of each system's performance capability. Such evaluations will be left up to the reader for his specific application needs. To allow the reader the necessary information to make his own decision, each report will identify the equipment's age and/or operating hours at the time of testing.

Each system will be examined individually to characterize emissions and power/heat production performance at power outlet levels where users of the technology are likely to operate. Controlled performance testing will be conducted at four electrical loads summarized in Table 1-5. The site's biogas production rate will be the limiting factor in how much electric power can be generated on site (maximum of 65 kW). For this reason, only one system will be operating during load testing. This will enable the highest volume of biogas to be fed to each system, such that performance evaluation at upper load levels can be conducted. However, based on current biogas production estimates, it is estimated that full load may not be achievable with the IC engine CHP system. If such conditions are encountered during the test, the GHG Center will perform load testing at the highest achievable power output level, the lowest achievable level (approximately 32 kW), and two additional points between this range.

Potential users are also likely to be interested in quantifying the highest heat recovery potential such that full benefits of the cogeneration systems can be utilized. The site currently does not have the thermal energy demand to make full use of all recovered heat. As such, for this test, the GHG Center will augment the heat demand of the site to quantify the highest heat recovery potential at the four loads. To achieve this, hot water temperature for the microturbine heat recovery unit will be set at 125 °F, and the IC engine heat recovery unit will be set at about 135 °F. These are the maximum allowable supply water temperatures of the two heat recovery systems, and are the range where maximum heat will be recovered with a return water temperature of 100 °F.

**Table 1-5. Verification Test Matrix**

## Efficiency and Emissions Performance Evaluations

**Controlled Load Testing – Microturbine CHP System**

| Test Condition (Percent of Rated Power Output) | Power Setting (kW) | Heat Exchanger Supply Temp. ($^oF$) | No of Replicate Test Runs Executed | Duration of Each Test Run | | |
|---|---|---|---|---|---|---|
| | | | | Power, Heat, and Efficiency Determination | CO, $NO_X$, $SO_2$, THC, TRS, $CO_2$, and $CH_4$ Emissions | NH3 and TPM Emissions |
| 100 | 30 | 125 | 3 | 30 mins | 30 mins | 120 mins |
| 75 | 22 | 125 | 3 | 30 mins | 30 mins | not tested |
| 60 | 18 | 125 | 3 | 30 mins | 30 mins | not tested |
| 50 | 15 | 125 | 3 | 30 mins | 30 mins | not tested |

**Controlled Load Testing – IC Engine CHP System**

| Test Condition (Percent of Rated Power Output) | Power Setting (kW) | Heat Exchanger Supply Temp. ($^oF$) | No of Replicate Test Runs Executed | Duration of Each Test Run | | |
|---|---|---|---|---|---|---|
| | | | | Power, Heat, and Efficiency Determination | CO, $NO_X$, $SO_2$, THC, TRS, $CO_2$, and $CH_4$ Emissions | NH3 and TPM Emissions |
| 100 | 100[a] | 135 | 3 | 60 mins | 60 mins | 120 mins |
| 75 | 75[a] | 135 | 3 | 60 mins | 60 mins | not tested |
| 60 | 60 | 135 | 3 | 60 mins | 60 mins | not tested |
| 50 | 50 | 135 | 3 | 60 mins | 60 mins | not tested |

**Testing at Normal Site Operating Conditions**

| | Power Setting (kW) | Heat Exchanger Supply Temp. ($^oF$) | No of Replicate Test Runs Executed | Duration of Each Test Run | | |
|---|---|---|---|---|---|---|
| | | | | Power, Heat, and Efficiency Determination | CO, $NO_X$, $SO_2$, THC, TRS, $CO_2$, and $CH_4$ Emissions | NH3 and TPM Emissions |
| Microturbine | 30 | 110 | 3 | 30 mins | 30 mins | not tested |
| IC Engine | 35 to 65 | 125 | 3 | 60mins | 60 mins | not tested |

## Power Quality and Emission Reduction Evaluations

**Extended Testing at Normal Site Operating Conditions**

| | Power Setting (kW) | Heat Exchanger Supply Temp. ($^oF$) | Duration of Testing | | |
|---|---|---|---|---|---|
| | | | Power Quality Determination | Total Energy Generated (electrical, thermal) | Emission Reductions from Electricity Offset |
| Microturbine | 30 | 110 | 1 week | 1 week | 1 week |
| IC Engine | 35 to 65 | 125 | | | |

[a] If sufficient biogas is not available to achieve this power output, load testing will be conducted at the highest achievable load (approx. 65 kW), the lowest achievable load (approx. 32 kW), and two loads between this range.

As shown in the verification test matrix (Table 1-5), three test runs, each lasting about 0.5-hour for the microturbine and 1-hour for the IC engine, will be executed at the four electrical loads. The microturbine and IC engine CHP systems will be allowed to stabilize at each load for 15 to 30 minutes before starting the test runs. During each test, simultaneous monitoring for power output, heat recovery rate, fuel consumption, ambient meteorological conditions, exhaust stack emission rate, and pollutant concentrations in the exhaust stack will be performed. Average electrical power output, heat recovery rate, energy conversion efficiency (electrical, thermal, and net), and exhaust stack concentration and emission rates will be reported for each load factor. Emission results for the following pollutants will be reported: $CO_2$, $CH_4$, $NO_X$, CO, sulfur dioxide ($SO_2$), total hydrocarbons (THCs), ammonia ($NH_3$), total particulate matter (TPM), and total reduced sulfur (TRS).

After the controlled load testing is completed, efficiency and emissions performance evaluations will be conducted at normal site operating conditions. Under normal conditions, the site plans to operate the microturbine at maximum electrical power output (30 kW nominal), while the IC engine will supply the remaining electricity (35 kW nominal). The heat demand is significantly lower at normal site conditions, as the site currently uses the heat for maintaining digester temperature. Under normal site operating conditions, the hot water supply temperature will be set at the levels determined by the site operator to provide sufficient heat to the digester (i.e., 110 $^oF$ for the microturbine and 125 $^oF$ for the IC engine). Three test runs, each lasting about 0.5 hour for the microturbine and 1-hour for the IC engine, will be execute at these settings. The results will indicate each system's electrical, thermal, and combined efficiency and air emission rates at normal site operating conditions.

After the efficiency and emissions performance evaluations are completed, additional verification data will be collected for a period of 1 week while each system is operating at normal site conditions. Both systems will be operated 24 hours per day, and will utilize all the biogas produced at the site. Continuous monitoring of electrical power generated, heat recovered, fuel consumed, ambient meteorological conditions, and power quality will be performed. The results of this extended monitoring will be used to report total energy generated (electrical and thermal) and average power quality data.

The parameters to be verified are listed below, followed by a brief description of each. Detailed descriptions of measurement and analysis methods are presented in Section 2.0, and data quality assessment procedures for each verification parameter are presented in Section 3.0.

**Verification Parameters**

**Power and Heat Production Performance**

- Electrical power output at selected loads, kW
- Heat recovery rate at selected loads, Btu/hr, kW
- Electrical efficiency at selected loads, %
- Thermal energy efficiency at selected loads, %
- Combined heat and power production efficiency at selected loads, %
- Total electrical energy generated, kWh
- Total thermal energy recovered, Btu

**Electrical Power Quality Performance**

- Electrical frequency, Hz
- Voltage output, VAC
- Power factor, %
- Voltage total harmonic distortion (THD), %
- Current THD, %

**Air Pollutant Emission Performance**

- CO, $NO_X$, THCs, $NH_3$, TPM, TRS, $CO_2$, and $CH_4$ concentrations at selected loads, ppmv, %
- CO, $NO_X$, THCs, $NH_3$, TPM, TRS, $CO_2$, and $CH_4$ emission rates at selected loads, lb/hr, lb/Btu, lb/kWh

**Emission Reductions**

- Estimated $NO_X$ emission reductions, lb $NO_X$, %
- Estimated GHG emission reductions, lb $CO_2$, %

### 1.5.1 Power and Heat Production Performance

Power production performance represents a key operating characteristic that is of great interest to purchasers, operators, and users of these systems. The GHG Center will install an electrical meter to measure the cumulative power generated by the microturbines. Fuel input will be measured using flow meters installed in the natural gas and blended gas flow streams. Gas sampling and energy content analysis of the blended gas will be performed to determine the LHV of the fuel supplied to the microturbines. Fuel energy-to-electricity conversion efficiency will be determined by dividing the average electrical power output by the heat input for each load condition.

Heat recovery rates will be verified simultaneously with power output measurements by metering the flow rate, hot (supply) and cold (return) water temperatures. Thermal energy conversion efficiency at each load will be determined by dividing the average heat recovered by the heat input. CHP production efficiency will be reported as the sum of electrical and thermal efficiencies at each operating load.

The sum of 1-minute average power output measurements and heat recovery rate measurements, collected over the 1-week extended testing period, will represent total electrical energy generated and thermal energy recovered.

Ambient temperature, relative humidity (RH), and barometric pressure will be measured throughout the verification period to support determination of electrical conversion efficiency. A detailed discussion of sampling procedures, analytical procedures, and measurement instruments related to heat and power production performance parameters is provided in Section 2.2.

### 1.5.2 Power Quality Performance

The monitoring and determination of power quality performance is required to insure compatibility with the electrical grid, and to demonstrate that the electricity will not interfere with or harm microelectronics and other sensitive electronic equipment within the facility. Power quality data is used to report exceptions, which describe the number and magnitude of incidents that fail to meet or exceed a power quality standard chosen. The Institute of Electrical and Electronics Engineers' Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems (IEEE 1993) contains standards for power quality measurements that will be followed. Power quality parameters will be determined over the 1-week of normal operation test conditions. The same wattmeter used to measure electric power output will be used to measure the power quality parameters listed earlier. The technical approach for verifying these parameters is described in Section 2.3.

### 1.5.3 Air Pollutant Emission Performance

The measurement of the emissions performance of the microturbine and IC engine are critical to any assessment of the environmental impact of the technology. Emissions testing for all pollutants, with the exception of $NH_3$ and TPM, will be conducted simultaneously with the efficiency determinations. Emission tests at each load will be repeated three times. This triplicate measurement design is based on U.S. EPA New Source Performance Standards (NSPS) guidelines for measuring emissions from stationary gas turbines (EPA, 1999). Concentration and emission rate measurements for CO, $NO_X$, THCs, $NH_3$, TPM, TRS, $CO_2$, and $CH_4$, will be conducted in the microturbine and IC engine exhaust stacks at the selected operating loads. Exhaust stack emission testing procedures, described in U.S. EPA's NSPS for stationary gas turbines, will be adapted to verify the verification parameters listed earlier. Concentration measurements will be reported in units of parts per million volume, dry basis (ppmvd) and corrected for 15 percent $O_2$ at the microturbine. Emission rates will be reported in units of mass/hour, mass/heat input, and mass/power output for both units. A detailed discussion of sampling procedures, analytical procedures, and measurement instruments is provided in Section 2.4.

### 1.5.4 Emission Reductions

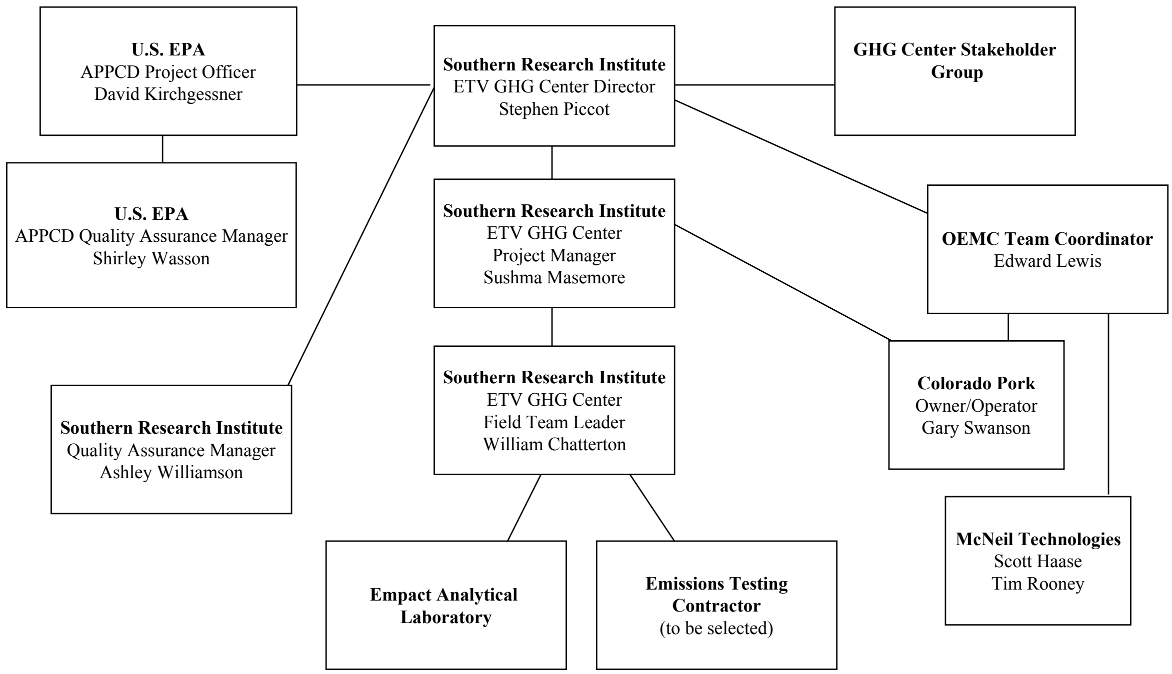
Emission reductions for $CO_2$ and $NO_X$ will be estimated by subtracting emissions from the on-site CHP system from emissions associated with a baseline electrical power generation technology. It will be assumed that the on-site CHP electrical power will reduce the need for the same amount of electricity from the local grid, after adjusting grid power needs upward to account for transmission line losses. The subtraction of the estimated emissions from the on-site units from the estimated emissions associated with the mix of power stations serving the local grid will yield an estimate of the $CO_2$ and $NO_X$ emission reductions over the testing period. Section 2.5 presents the procedures for estimating emission reduction from utility grid electricity production.

The GHG Center does not plan to conduct life cycle emission reduction calculations, which takes into account emission savings from anaerobically digesting waste that would normally be disposed in an open lagoon, sequestering carbon in the soil amendment, utilizing waste heat that would normally be produced by on-site boilers, and consideration of $CO_2$ rejected during the wet biogas treatment process. A full life cycle emission estimation procedure is beyond the scope of this verification, and would require a national assessment of "baseline" waste management techniques and heat production systems. For this reason, the GHG Center plans to estimate emission reductions for the electricity generation component only, as described above.

## 1.6 ORGANIZATION

Figure 1-10 presents the project organization chart. The following section discusses functions, responsibilities, and lines of communications for the verification test participants.

**Figure 1-10. Project Organization**




SRI's GHG Center has overall responsibility for planning and ensuring the successful implementation of this verification test. The GHG Center will ensure that effective coordination occurs, schedules are developed and adhered to, effective planning occurs, and high-quality independent testing and reporting occur.

Mr. Stephen Piccot is the GHG Center Director. He will ensure the staff and resources are available to complete this verification as defined in this Test Plan. He will review the Test Plan and Reports to ensure they are consistent with ETV operating principles. He will oversee the activities of the GHG Center staff, and provide management support where needed. Mr. Piccot will sign the Verification Statement, along with the EPA-ORD Laboratory Director.

The GHG Center's Ms. Sushma Masemore will have the overall responsibility as the Project Manager. She will be responsible for overseeing field data collection activities of the GHG Center's Field Team Leader, including assessment of DQOs prior to completion of testing. Ms. Masemore will follow the procedures outlined in Sections 2.0 and 3.0 to make this determination, and she will have the authority to repeat tests as determined necessary to ensure that data quality goals are met. Should a situation arise during testing that could affect the health or safety of any personnel, Ms. Masemore will have full authority to suspend testing. She will also have the authority to suspend testing if quality problems occur. In both cases, she may resume testing when problems are resolved. Ms. Masemore will be responsible for maintaining communication with the OEMC team, EPA, the GHG Center, and stakeholders.

Mr. William Chatterton will serve as the Field Team Leader, and will support Ms. Masemore's data quality determination activities. Mr. Chatterton will provide field support for activities related to all measurements and data collected. He will install and operate the measurement instruments, supervise and document activities conducted by the emissions testing contractor, collect gas samples and coordinate sample analysis with the laboratory, and ensure that QA/QC procedures outlined in Section 2.0 are followed. He will submit all results to the Project Manager, such that it can be determined that the DQOs are met. He will be responsible for ensuring that performance data collected by continuously monitored instruments and manual sampling techniques are based on procedures described in Section 4.0.

SRI's Quality Assurance Manager, Dr. Ashley Williamson, will review this Test Plan. He will also review the results from the verification test, and conduct an Audit of Data Quality (ADQ), described in Section 4.4.4. Dr. Williamson will report the results of the internal audits and corrective actions to the GHG Center Director. The results will be used to prepare the final Report.

Mr. Edward Lewis of OEMC and Mr. Greg Swanson of Colorado Pork will serve as the primary contact persons for the OEMC team. They will provide technical assistance, assist in the installation of measurement instruments, and coordinate operation of the microturbine and IC engine at the test site. They will ensure the units are available and accessible to the GHG Center for the duration of the test. The OEMC team will also review the Test Plan and Reports and provide written comments.

EPA-ORD will provide oversight and QA support for this verification. The APPCD Project Officer, Dr. David Kirchgessner, is responsible for obtaining final approval of the Test Plan and Report. The APPCD QA Manager reviews and approves the Test Plan and the final Report to ensure they meet the GHG Center QMP requirements and represent sound scientific practices.

## 1.7 SCHEDULE

The tentative schedule of activities for testing at Colorado Pork is:

| | |
|---|---|
| **VERIFICATION TEST PLAN DEVELOPMENT** | |
| GHG Center Internal Draft Development | April 15 - May 31, 2002 |
| OEMC Team Review/Revision | June 3 – June 13, 2002 |
| EPA and Industry Peer-Review/Revision | July 8 – November 27, 2002 |
| Final Test Plan Posted | December 9, 2002 |
| **VERIFICATION TESTING AND ANALYSIS** | |
| Measurement Instrument Installation/Shakedown | January 27 – January 31, 2003 |
| Field Testing | February 10 – February 21, 2003 |
| Data Validation and Analysis | February 24 – March 10, 2003 |
| **VERIFICATION REPORT DEVELOPMENT** | |
| GHG Center Internal Draft Development | March 11 – March 28, 2003 |
| OEMC Team Review/Revision | March 31 – April 11, 2003 |
| EPA and Industry Peer-Review/Revision | April 14 – May 14, 2003 |
| Final Report Posted | May 31, 2003 |

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# 2.0 VERIFICATION APPROACH

## 2.1 OVERVIEW

CHP systems operating on anaerobic digestion gas are a relatively new application of DG technologies; the availability of performance data in such applications is limited and in great demand. The GHG Center's stakeholder groups and other organizations concerned with DG have a specific interest in obtaining verified field data on the emissions, technical, and operational performance of DG systems in agricultural applications.

Performance parameters of greatest interest include electrical power output and quality, thermal-to-electrical energy conversion efficiency, thermal energy recovery efficiency, exhaust emissions of conventional air pollutants and GHGs, GHG emission reductions, operational availability, maintenance requirements, and economic performance. The test approach described here focuses on assessing those performance parameters for potential future customers of the microturbine and IC engine technologies. Long-term evaluations cannot be performed with available resources, so economic performance and maintenance requirements will not be evaluated. The OEMC team plans to perform economic performance evaluation at Colorado Pork, and its results will be publicly available. The ETV verification test will evaluate the technical performance of two CHP systems at the conditions encountered during testing.

In developing the verification strategy, the GHG Center has applied existing standards for large gas-fired turbines, large IC engines, engineering judgement, previous capability in evaluating DG systems, and technical input from the verification team. For the microturbine CHP system, electrical power output and efficiency determination guidelines contained in the American Society of Mechanical Engineers (ASME) *Performance Test Code for Gas Turbines, PTC-22* (ASME 1997a) have been adopted to evaluate electric power production and electrical energy conversion efficiency performance. Some variations in the PTC-22 requirements were made to reflect the small-scale of the microturbine. For the IC engine CHP system, electrical power output and efficiency determination guidelines contained in the ASME *Performance Test Code for Reciprocating Internal Combustion Engines, PTC-17* (ASME 1997b) have been adopted. The strategy for determining thermal energy recovery is adopted from guidelines described in the American National Standards Institute/American Society of Heating, Refrigeration and Air-Conditioning Engineers (ANSI/ASHRAE) *Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems* (ANSI/ASHRAE 1992).

Exhaust stack emissions testing procedures, described in U.S. EPA's NSPS for emissions from stationary gas turbines, 40 CFR60, Subpart GG (EPA 1999b) have been adopted for GHG and criteria pollutant emissions testing. Power quality standards used in this verification are based on the Institute of Electrical and Electronics Engineers' (IEEE) *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* (IEEE 1993).

Verification testing at four operating loads and continuous monitoring at normal site conditions will be performed to address the following verification parameters:

**Power and Heat Production Performance (Section 2.2)**

- Electrical power output at selected loads, kW
- Heat recovery rate at selected loads, Btu/hr
- Electrical efficiency at selected loads, %
- Thermal energy efficiency at selected loads, %
- CHP production efficiency at selected loads, %
- Total electrical energy generated, kWh
- Total thermal energy recovered, Btu

**Electrical Power Quality Performance (Section 2.3)**

- Electrical frequency, Hz
- Voltage output, VAC
- Power factor, %
- Voltage THD, %
- Current THD, %

**Air Pollutant Emission Performance (Section 2.4)**

- CO, $NO_X$, THCs, $NH_3$, TPM, TRS, $CO_2$, and $CH_4$ concentrations at selected loads, ppmv, %
- CO, $NO_X$, THCs, $NH_3$, TPM, TRS, $CO_2$, and $CH_4$ emission rates at selected loads, lb/hr, lb/Btu, lb/kWh

**Emission Reductions (Section 2.5)**

- Estimated $NO_X$ emission reductions, lb $NO_X$, %
- Estimated GHG emission reductions, lb $CO_2$, %

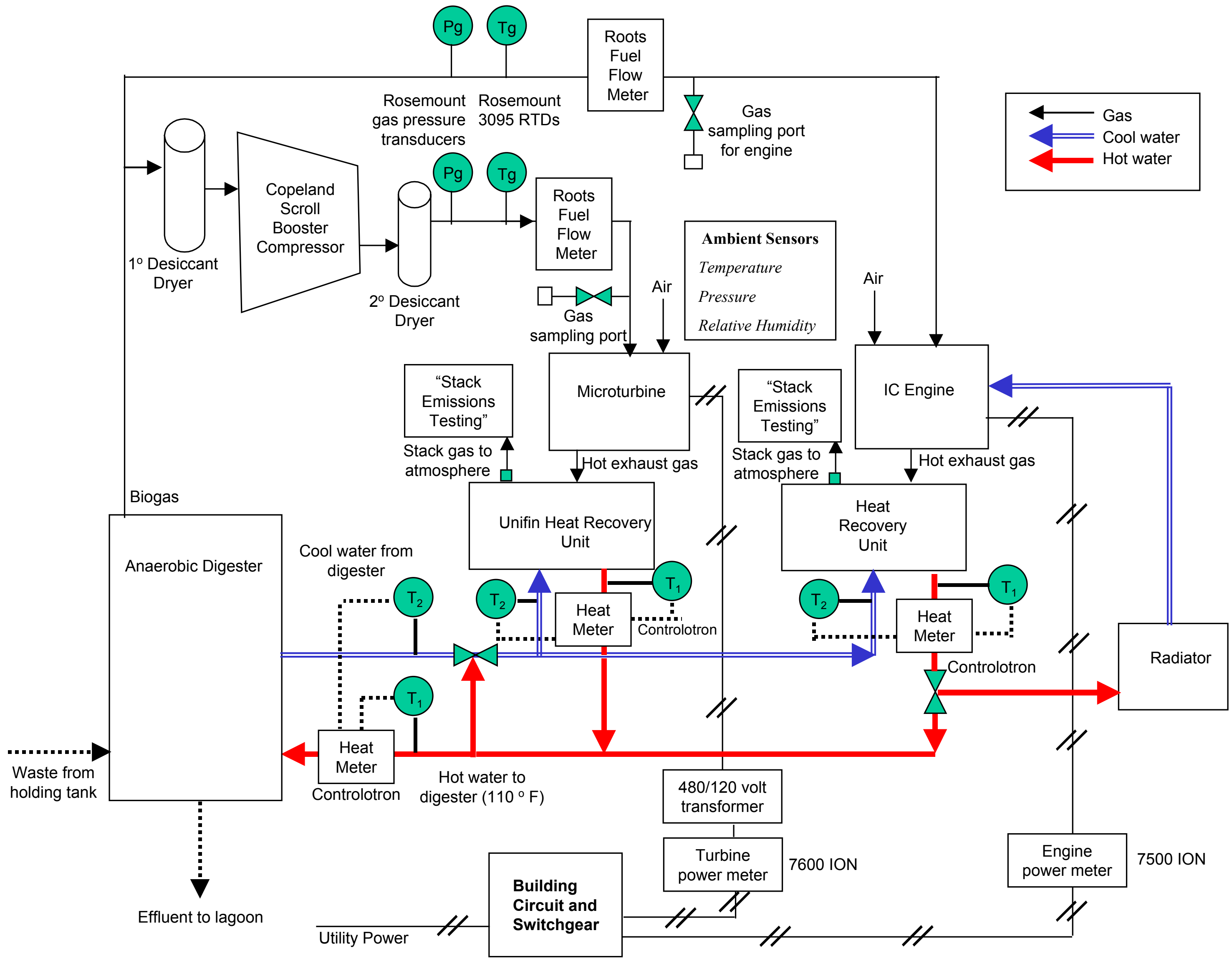
Figure 2-1 illustrates the measurement system to be employed. Detailed descriptions of testing and analytical methods are provided sequentially in Sections 2.2 through 2.5.

## 2.2 POWER AND HEAT PRODUCTION PERFORMANCE

Electric power and heat performance parameters for the microturbine and IC engine CHP systems will be evaluated at the four operating loads listed in Table 1-5. Simultaneous measurements of electric power output, heat recovery rate, fuel consumption, ambient meteorological conditions, and exhaust emissions will be made during testing at each load. A step-by-step procedure for conducting the load tests is provided in Appendix A-1, and a log form associated with this activity is provided in Appendix A-2. The following sub-sections discuss the measurements, calculations, and instruments associated with the power and heat performance parameters.

After the load testing is completed, the CHP systems will operate at normal site conditions for a period of at least 1 week. The sum of electric power generated and heat recovery rate during this time period will represent the total electrical energy generated and thermal energy recovered.

**Figure 2.1 Schematic of Measurement System**



### 2.2.1 Electric Power Output and Efficiency Determination

The GHG Center will simultaneously measure electric power output, fuel consumption, and ambient meteorological conditions to determine electrical efficiency. The time-synchronized data will be used to compute electrical efficiency as specified in PTC-22 for microturbines and PTC-17 for engines (ASME 1997a, ASME 1997b). For microturbines, PTC-22 mandates using electric power data collected over time intervals of not less than 4 minutes and not greater than 30 minutes to compute electrical efficiency (PTC-22, Sections 3.4.3 and 4.12.3). For reciprocating engine measurements, PTC-17 specifies intervals of not less than one hour and not greater than three hours (PTC-17, Section 3.4.6).

These restrictions minimize electrical efficiency determination uncertainties due to changes in operating conditions (e.g., turbine or engine speed, ambient conditions). Within this time period, PTC-22 and PTC-17 specify the maximum permissible limits in power output, fuel input, atmospheric conditions, and other parameters to be less than the values shown in Tables 2-1 and 2-2. The GHG Center will use only those time periods that meet these requirements to compute power and heat performance parameters. Should the variation in any measurement parameters listed in the tables exceed the specified levels, the load test will be considered invalid and the test will be repeated.

**Table 2-1. Permissible Variations in Power, Fuel, and Atmospheric Conditions (Microturbine Tests)**

| Measured Parameter | Maximum Permissible Variation |
|---|---|
| Ambient air temperature | ± 4 $^{o}$F |
| Barometric pressure | ± 0.5 % |
| Fuel flow rate | ± 2.0 % |
| Power factor | ± 2.0 % |
| Power output | ± 2.0 % |

**Table 2-2. Permissible Variations in Power, Fuel, and Atmospheric Conditions (IC Engine Tests)**

| Measured Parameter | Maximum Permissible Variation |
|---|---|
| Ambient air temperature | ± 5 $^{o}$F |
| Barometric pressure | ± 1.0 % |
| Fuel gas pressure at the meter | ± 2.0 % |
| Fuel gas temperature at the meter | ± 5 $^{o}$F |
| Power output | ± 3.0 % |

The GHG Center will conduct three valid test runs at each load condition. For the microturbine, the test period for each load test will be about 30 minutes in duration. The test period for the IC engine will be about 60 minutes. Average electrical efficiency will be the mean of the three test runs. For each test run, electrical efficiency is per ASME PTC-22, Section 5.3:

$$\eta_{e,\,j} = \frac{3412.14\ kW_j}{HI_j} * 100 \qquad \text{(Eqn. 1)}$$

Where:
$\eta_{e,j}$ = Electrical efficiency at load condition j, %
$kW_j$ = Average electrical power output at load condition j, kW
$HI_j$ = Average LHV heat input for load condition j, Btu/hr
3412.14 = Btu/hr per kW

The GHG Center will install two separate power meters downstream of the 120 volt transformers to measure power output (Figure 2-1). The voltage transformers reduce electricity supplied at 480 volts by the microturbine and IC engine, to that needed by the facility. This means that the power measured and the resulting efficiencies, will represent actual power delivered to the site after booster compressor, transformer, and other parasitic losses. Section 2.2.3.1 describes the power meters to be used.

Average electrical power output will be the mathematical average of the 1-minute readings measured by the power meter over each sampling period (30 or 60 minutes), as shown in Equation 2.

$$kW = \frac{\sum_{i=1}^{i=nr} kW_i}{nr} \qquad \text{(Eqn. 2)}$$

Where:
KW = Average electrical power output at load condition j, kW
$kW_i$ = Average electrical power output during minute i as measured by the power meter, kW
nr = Number of 1-minute averages logged during the test run

Heat input, shown in Equation 1, is the fuel volumetric flow rate during the test period multiplied by the average fuel LHV. Heat input to the microturbine or IC engine, normalized to an hourly rate for each test run will be:

$$HI_j = LHV_{avg,j} * V_{avg,j} \qquad \text{(Eqn. 3)}$$

Where:
$HI_j$ = Heat input at load condition j, Btu/hr
$LHV_{avg,j}$ = Average LHV at load condition j, Btu/scf
$V_{avg,j}$ = Average fuel flow rate at load condition j, scfh (Eqn. 4)

To measure fuel flow rate, the GHG Center will use site's positive displacement (Roots) meters, located upstream of the microturbine and IC engine fuel intakes. The microturbine Roots meter will measure the gas flows consumed after compression and biogas treatment stages. Each Roots meter will measure the actual volume of the gas under site conditions, uncompensated for temperature and pressure. Equation 3 requires the actual volumetric flow rate to be corrected to standard conditions [60 °F, 14.73 pounds per square inch absolute (psia)]. To enable this, temperature and pressure sensors will be installed in the gas manifolds to correct the measured flow rates to standard conditions. Figure 2-1 illustrates the locations of the flow meters and temperature/pressure sensors, and Equation 4 shows the volume correction methodology. Sections 2.2.3.3 and 2.2.3.4 describe the fuel gas meters and other measurement sensors in more detail.

$$V = V_g \left( \frac{P_g}{14.73} \right) \left( \frac{520}{T_g} \right) \left( \frac{Z_{std}}{Z_g} \right) \quad \text{(Eqn. 4)}$$

Where:

| | | |
|---|---|---|
| V | = | Fuel flow rate, compensated for pressure, temperature, and compressibility, scfh |
| $V_g$ | = | Average volumetric flow rate of fuel gas recorded during the test run, acfh |
| $P_g$ | = | Fuel gas pressure, represented as the sum of gauge pressure and ambient pressure from barometric pressure sensor, psia |
| 14.73 | = | Gas industry standard pressure, psia |
| 520 | = | Gas industry standard temperature, (60 $^oF$ or 520 R) |
| $T_g$ | = | Fuel gas temperature, R ($^oF$ + 460) |
| $Z_{std}$ | = | Compressibility factor at standard pressure and temperature, based on gas analysis performed per ASTM D3588 |
| $Z_g$ | = | Compressibility factor at fuel gas pressure and temperature, based on gas analysis performed per ASTM D3588 |

To determine LHV in terms of Btu/scf, GHG Center personnel will collect two gas samples during each test run. The Field Team Leader will forward the samples to an independent laboratory for compositional analysis in accordance with ASTM Specification D1945, and LHV determination using ASTM Specification D3588. Other physical properties, such as specific gravity and compressibility factor, will also be reported per ASTM D3588.

The analytical laboratory will report the LHV values on a dry basis, corrected to standard conditions (14.73 psia and 60 $^oF$). However, the fuel gas will inherently contain water vapor. Therefore, the compositional results must be adjusted to account for the fact that the water has displaced some gas, and lowered the heating value. It is necessary to remove the effect of water because, although water has a heating value, it is only a condensation effect and does not contribute to energy production. ASTM D3588 provides an extended procedure for correcting the LHV, and consists of reducing LHV from dry basis to wet basis as follows:

$$LHV = LHV_{dry,i} \ (1 - x_{w,i}) \quad \text{(Eqn. 5)}$$

Where:

| | | |
|---|---|---|
| LHV | = | LHV for gas sample i, corrected for water vapor, Btu/scf |
| $LHV_{dry,I}$ | = | LHV for gas sample i, reported on dry basis by analytical laboratory, Btu/scf |
| $x_{w,i}$ | = | mole fraction of water in gas sample i |

The term "$x_w$" is the mole fraction of water vapor in the gas stream. The anticipated value is unknown at this writing because the facility has not yet installed the gas treatment system. It could also vary depending on the blended biogas to natural gas ratio. To account for fuel moisture, and its effects on LHV, GHG Center personnel will determine fuel gas moisture content in the field by ASTM D4888-88 "Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes" (ASTM 1999). Appendix A-3 and A-4b provides the procedure and log form, respectively.

The water vapor data will be reported by an analytical laboratory in units of milligrams of water per liter of gas sampled (mg/l). Conversion of the data to the molar ratio required in Equation 6 requires a train of calculations. First, GHG Center analysts will calculate the molecular weight of the dry blended gas from the associated fuel gas sample data:

$$MW_{sample} = \sum_{1}^{n} p_n MW_n \qquad \text{(Eqn. 6)}$$

Where:
$MW_{sample}$ = Fuel gas molecular weight, g/g.mol
$p_n$ = Volume proportion of component n
$MW_n$ = Molecular weight of component n

The specific molar mass of the dry fuel gas is:

$$v_{mol} = \frac{R^* T}{p} \qquad \text{(Eqn. 7)}$$

Where:
$v_{mol}$ = Gram molar volume of the fuel gas, l/g.mol
R* = 0.08206, atm.l/g.mol.K (universal gas constant)
T = Fuel gas temperature, recorded by DAS, K
p = Sampling pressure, barometric pressure recorded by DAS divided by 14.696, atm

The density of the dry fuel gas at the sampling conditions is:

$$\rho_{sample} = \frac{MW_{sample}}{v_{mol}} \qquad \text{(Eqn. 8)}$$

Where:
$\rho_{sample}$ = Sample density, g/l

The molar ratio, then, is

$$x_w = \frac{\frac{(g/l)_{H2O}}{18}}{\frac{\rho_{sample}}{MW_{sample}} + \frac{(g/l)_{H2O}}{18}} \qquad \text{(Eqn. 9)}$$

Where:
$x_w$ = Mole fraction of water in the gas sample
$(g/l)_{H2O}$ = Water vapor content measured by ASTM D4888-88, g/L (mg/l÷1000)
18 = Molecular weight of water

For each fuel sample, the GHG Center will determine the molar fraction of water vapor in that sample and enter the value into Equation 6.

Section 2.2.3 describes the fuel gas sampling and analysis procedures.

### 2.2.2 Heat Recovery Rate and Thermal Efficiency Determination

The CHP systems produce heat as a byproduct of electricity generation. The CHP heat recovery performance is a function of the amount of that heat used by other processes. The test facility uses heat exchangers to recover microturbine and IC engine heat into a circulating hot water system. This recovered heat is primarily used to maintain the digester's temperature. Unused heat is expelled through the microturbine stack and/or external radiator. The site operator has identified additional process equipment at the farm which are good candidates for utilizing the excess heat. During the test, Colorado Pork may bring some of their equipment online to utilize all or most of the heat recovered by the CHP systems. The OEMC team has expressed interest in verifying the maximum heat recovery potential of each CHP system, such that the site could make informed decisions about using excess heat. This verification will therefore attempt to quantify maximum heat recovery potential during full load testing. Assuming the return water temperature is 100 $^{o}$F, the hot water supply temperature for the microturbine heat recovery unit will be manually set to 125 °F, and the IC engine heat recovery unit will be set to about 135 °F. These are the maximum allowable supply water temperatures of the two heat recovery systems, and are the conditions when maximum heat should be recovered.

Preliminary calculations suggest that sufficient thermal demand exists to utilize all the recoverable heat produced by the microturbine or IC engine CHP systems during the load testing. In the event the digester is unable to utilize all the recoverable heat, the site operator will assist in maximizing heat recovery by artificially increasing the thermal demand. This will consist of one or more of the following measures: load testing during cooler ambient temperatures in early morning or late evening, discarding excess heat through the external radiator, dumping hot water, bringing other equipment online that could use the heat, and/or taking other safe measures which will not impact normal farm operations.

The following equation provides a standard method to determine heat recovery rates according to ANSI/ASHRAE Standard 125 (ASHRAE 1992).

$$Q = 0.13368\, V_l\, \rho\, Cp\, (T1\text{-}T2)\, 60 \qquad \text{(Eqn. 10)}$$

Where:

Q = Heat recovery rate, Btu/hr
0.13368= $ft^3$ per gal
60 = min per hour
$V_l$ = Total volume of liquid passing through the system during a minute, gal/min
ρ = Density of liquid evaluated at the average fluid temperature, [(T2+T1)/2], lb/$ft^3$
Cp = Specific heat of liquid evaluated at the average fluid temperature, [(T2 + T1)/2], Btu/lb, $^{o}$F
T1 = Temperature of heated liquid exiting the heat exchanger ("supply"), $^{o}$F
T2 = Temperature of cooled liquid entering the heat exchanger ("return"), $^{o}$F

The heat recovery rate determination requires the definition of the density and specific heat at actual operating temperatures. For both CHP systems at Colorado Pork, the heat transfer fluid is pure water (no glycol is added). The properties of water are well defined and are available from reliable publications. Because the water contains no additives that would affect these properties, test personnel will not conduct fluid sampling or analysis.

The GHG Center will use a portable Controlotron (Model 1010EP1) heat meter to quantify the recovered heat. The heat meter contains ultrasonic transmitters to measure fluid velocity and resistive temperature detectors (RTDs) to measure the supply and return water temperatures. Algorithms within the heat meter software use physical properties of the working fluid to calculate fluid flow rate and heat recovery rate. The heat meter provides four analog outputs as follows:

| **Measurement** | **Units** |
|---|---|
| Fluid flow rate | gal/min |
| Heat recovery rate | Btu/min |
| Return temperature | $^{o}F$ |
| Supply temperature | $^{o}F$ |

During all test periods, the GHG Center's DAS will log the heat meter outputs as 1-minute averages.

A description of the ultrasonic flow meter is provided in Section 2.2.3.7.

The 1-minute average heat recovery values will be averaged over the time intervals corresponding to each load test and normalized to Btu/hr. The following equation will be used to compute thermal efficiency.

$$\eta_{Th,\,j} = Q_j \,/\, HI_j \qquad \text{(Eqn. 11)}$$

Where:

$\eta_{Th,\,j}$ = Thermal efficiency at load condition j, %

$Q_j$ = Average heat recovered for load condition j, Btu/hr

$HI_j$ = Average heat input using LHV for load condition j, Btu/hr (Equation 3)

The Reports will state CHP production efficiency separately for the microturbine and engine as the sum of $N_e$ and $N_{th}$ for each valid test run. The Report will also summarize average CHP production efficiency at each load level during controlled load testing, during normal site operating conditions, and for the extended testing period.

Figure 2-1 shows the location of the ultrasonic transmitters and temperature sensors. During load testing, the sensors will be located as close as practicable to the inlet and outlet of the supply and return lines. The ultrasonic transmitters must be surface-mounted, while the RTDs can be surface-mounted or inserted into thermowells (depending on pipe size and configuration). The engine's steel piping is 4-inch diameter (nominal). For the verification at this machine, the GHG Center will insert the RTDs into thermowells. The microturbine's steel pipeline is smaller (1.25-inch nominal), so surface mounted RTDs will be used. Per manufacturers' recommendations, the Field Team Leader will wrap insulation around the surface-mounted RTDs to minimize temperature reading variations due to ambient conditions.

During normal operations, the facility will consume less heat than the maximum rate determined above. To assess actual heat used by the digester, the GHG Center will relocate the heat meter sensors to the digester's hot- and cold-water manifold after load testing is completed. The difference between maximum heat recovery rate minus heat actually used by the digester will represent useful thermal energy that could be employed elsewhere, such as for space heating. Continuous 1-minute data will be collected over a 1-week period, and the sum of the 1-minute heat rates will represent the total recovered thermal energy used by the digester.

### 2.2.3 Measurement Instruments

#### 2.2.3.1 Power Output Measurements

A digital power meter, manufactured by Power Measurements Ltd. (Model 7600 ION) will be used to measure the electric power output from the microturbine. A Model 7500 ION will measure the electric power output from the engine. Each meter scans all power parameters once per second and sends the data to the DAS. The DAS then computes and records 1-minute averages. Section 4.0 provides further discussion of the DAS. The 1-minute average power output readings will be used to compute electrical efficiency at each load condition. The power meter's kWh recording function will be used to report kWh during the 1-week of continuous monitoring.

The power meters will be installed on the 120-volt circuit, after the transformer, and will measure the electricity actually used by the site. After installation, each meter will operate continuously, unattended, and will not require further adjustments. Prior to use in the field, the meters will be factory calibrated to IEC687 SO.2 and ANSI C12.20 CAO.2 standards for accuracy. Details regarding this and additional QA/QC checks (instrument setup, calibration, and sensor function checks) on this instrument are provided in Section 3.2.

#### 2.2.3.2 Fuel Gas Composition, Heating Value, and Compressibility Factor Analysis

Fuel gas samples will be collected during efficiency and emissions load testing. The gas samples will be submitted to an analytical laboratory for compositional analyses, LHV, and compressibility factor determinations. A minimum of two samples will be collected per test condition (i.e., two samples while the microturbine operates at 100 percent power, two samples at 75 percent power). The average LHV will be used to compute electrical and thermal efficiencies (Equations 1 and 11). The compressibility factor and moisture analysis data will be used to correct fuel gas flow rate to standard conditions (Equation 4).

Gas samples will be manually collected at an access port in the fuel line located prior to the flow meters (Figure 2-1). The port is downstream of a ball valve and consists of a 0.25-inch NPT union. Samples will be extracted into stainless steel canisters provided by the analytical laboratory (Empact Analytical Laboratory of Denver, Colorado). The canisters are pre-evacuated 600-milliliters (ml) vessels with valves on the inlet and outlet sides. Prior to sample collection, canister pressure will be checked using a vacuum gauge to document that the canisters are under vacuum and are, therefore, leak free. Canisters that are not fully evacuated upon receipt from the laboratory will not be used for testing. During testing, the connections between the canisters and the fuel sampling port will be screened with a hand-held hydrocarbon analyzer to check for leaks in the system. Leaks will be corrected prior to sampling. In addition, the canisters will be purged with fuel for between 15 and 30 seconds to ensure that a pure fuel sample is collected. Appendix A-3 contains detailed procedures that will be followed, and Appendices A-4 and A-5 contain sampling log and chain-of-custody forms.

The collected samples will be submitted to Empact Analytical Laboratory for compositional analysis in accordance with ASTM Specification D1945 for quantification of speciated hydrocarbons including $CH_4$ (C1 through pentane C5), heavier hydrocarbons (grouped as hexanes plus C6+), $N_2$, $O_2$, and $CO_2$. To ensure that moisture in the gas sample is vaporized prior to analysis, the laboratory will equilibrate each sample cylinder at the temperature at which the sample was collected, or warmer. During analysis, sample gas is injected into a Hewlett Packard 589011 gas chromatograph equipped with a molecular sieve column and a flame ionization detector. Components are physically separated on the columns and the resultant areas under the chart trace are determined for each compound. These areas are compared to the areas of the same compounds contained in a calibration reference standard that is analyzed under identical conditions. The reference standard areas are used to determine instrument response factors for each compound, and these factors are used to calculate the component concentrations in the sample. Data is acquired and recorded by a Hewlett Packard 339611 integrator.

In addition to the ASTM D1945 compositional analyses, Gas Processors Association (GPA) Method 2286 will provide an extended analysis to quantify concentrations of $H_2S$ (GPA 2000). GPA Method 2286 is essentially an extension of the ASTM D1945 procedures that uses additional chromatographic columns to separate $H_2S$ and heavier hydrocarbons. After injection into the GC, the sample is split. The first column separates and detects oxygen, nitrogen, $H_2S$, and $CH_4$ using the thermal conductivity detector referenced above. The second column separates ethane through normal pentane and employs a FID. The third section, not needed for this testing, separates and quantifies iso-pentane through tetradecane using a third column and a second FID. Consistent with the calibration procedures specified in ASTM D1945, analytical response factors for each compound are established by analyzing a calibration reference standard under identical conditions. Data is acquired and recorded by a Hewlett Packard 339611 integrator.

Instrumentation is calibrated weekly with the reference standards as a continuous calibration check. During calibrations, the analytical response factors generated for each compound analyzed are programmed into the instrument. Instrument accuracy is ± 0.2 percent full-scale, but allowable method error during calibration is ± 1 percent of the reference value of each gas component. The instrument is re-calibrated whenever its performance is outside the acceptable calibration limit of ± 1 percent for each component. Calibration records will be obtained and reviewed by the GHG Center.

The laboratory will use the compositional data to calculate the gross (HHV) and net (LHV) heating values (dry, standard conditions), compressibility factor, and the specific gravity of the gas per ASTM Specification D3588 (ASTM 2001a). The data quality of the heating value determinations is related to the repeatability of the ASTM D1945 analysis discussed above (ASTM 2001b). Provided the analytical repeatability criteria are met, ASTM D3588 specifies that LHV repeatability is approximately 1.2 Btu/1,000 $ft^3$ or about 0.1 percent.

#### 2.2.3.3 Fuel Gas Moisture Analysis

GHG Center personnel will determine fuel gas moisture content in the field by ASTM D4888-88 (ASTM 1999). In this test, a calibrated hand pump (Drager 18350 or equivalent) passes the gas through a detector tube (Drager 26228 or equivalent) filled with a specially prepared chemical. Any water vapor present in the sample reacts with the chemical to produce a color change or stain. The length of the stain, when exposed to a measured volume of gas, is directly proportional to the amount of water vapor in the gas. The test operator compares the length of the stain to the manufacturer's calibration scale to yield water vapor content in milligram per liter (mg/l). The analytical range is selectable based on anticipated vapor levels. Accuracy of the ASTM procedure is approximately 25 percent of reading, and the tubes are sensitive to 1 mg/l of $H_2O$.

The Field Team Leader will acquire at least one moisture sample in conjunction with each fuel gas sample for a total of two per load test run. As a check for the method's repeatability, he will acquire back-to-back moisture samples at least three times per day during load tests. Each back-to-back sample will be collected immediately after the preceding moisture sample. Logged values should agree with each other within 25 percent. Appendix A-4b provides the log form.

2.2.3.4 Fuel Gas Meters

Fuel gas meters are used to measure fuel flow rates to the microturbine and IC engine. The average flow rate, multiplied by the average LHV, yields average heat input to the generators (Equation 3). The flow rate measurements are also used to determine operational stability during load testing.

The test facility monitors digester gas flow rates with separate meters. Both meters are Roots (Model 2M175 SSM, Series B3) rotary positive displacement meters manufactured by DMD-Dresser (Figure 2-1). The meters' rated capacities are 2,000 actual cubic feet per hour (acfh), or approximately 33 cubic feet per minute (cfm). This capacity is appropriate for the microturbine's expected demand of 2 to 10 actual cubic feet per minute (acfm) and the engine's demand of 15 to 30 acfm. Certified accuracy of the meter is ± 1.0 percent of reading.

Each gas meter has a totalizing counter, or "index", which shows the running total of the gas volume that has passed through the meter. For example, as the microturbine uses digester gas, the index reading will increase. A given increase, combined with the time required for that increase, yields a time-based flow rate. Each meter's index reads directly to the nearest whole cubic foot with a cycling "hash mark" which allows a resolution of the meter reading to 0.2 acf. The GHG Center will acquire the index reading at 5-minute intervals during each test run. Appendix A-7 contains the appropriate field data form.

For each 5-minute period, actual volumetric fuel flow, normalized to an hourly rate, is:

$$V_{g,i} = \frac{(V_{final} - V_{initial})_i}{t_i} * 60 \qquad \text{(Eqn. 12)}$$

Where:

| | | |
|---|---|---|
| $V_{g,i}$ | = | Volumetric flow rate during meter reading period i, acfh |
| $V_{final}$ and $V_{initial}$ | = | Fuel volume flow at the beginning and end of meter reading period i, acf |
| i | = | Number of meter readings during the test run<br>6 per 30 min run, 12 per hour run, nominal |
| $t_i$ | = | Meter reading period i duration, minutes (5 minutes, nominal) |

Table 2-1 specifies that the maximum permissible variation in fuel flow at the microturbine is ± 2.0 percent. If all individual observations, normalized to an hourly flow rate, vary from the average hourly flow rate by ≤ 2.0 percent, the test run will fulfill the ± 2.0 percent specification. If any observation exceeds this specification, the Field Team Leader will make all reasonable efforts to eliminate sources of excess variation and repeat the test run. For the IC engine tests, PTC-17 does not contain a similar permissible fuel flow variation specification. At the end of each engine test run, the GHG Center will compute and record the fuel flow variation for information only.

2.2.3.5 Fuel Gas Temperature and Pressure Measurements

Fuel gas temperature and pressure data are used to convert measured fuel flow rate to standard conditions, and verify PTC-17 stability requirements. The following paragraphs describe the instruments to be used.

The DAS will record 1-minute average fuel temperatures as monitored by a Rosemount 3095 RTD. The sensor's location will be in a thermowell in the pipeline adjacent to the pressure transducer (Figure 2-1).

The RTD's range is from 0 to 1,200 $^{o}$F, ± 0.01 percent of full-scale. The GHG Center will obtain and review the National Institute for Standards and Technology (NIST) traceable factory calibration documents to ensure achievement of the accuracy goal. In addition, the Field Team Leader will perform reasonableness checks during testing by comparing readings recorded by the DAS to those reported by a portable hand-held unit prior to insertion into the pipeline. GHG Center analysts will compute the average fuel gas temperature for each test run and the resulting value ($^{o}$F + 460) will be used as the "$T_g$" term in Equation 4.

The GHG Center expects the fuel pressure to be reasonably stable during each test run. Pressures expected are approximately 17 inches water gauge (or 0.614 psig) above local ambient (or "station") barometric pressure. At the test facility elevation of approximately 3,615 feet, expected station pressure is approximately 12.916 psia. Total fuel gas pressure will be approximately 13.530 psia. A Rosemount (Model 3051) "smart" pressure transducer will monitor fuel gas pressure in the common fuel gas header upstream of the gas meters (Figure 2-1). Rosemount will set the full-scale range at 0 to 15.000 psia and perform a factory calibration prior to the verification. The sensor's accuracy is ± 0.075 percent of full-scale. The DAS will record 1-minute averages. The Field Team Leader will enter the average fuel gas pressure for each test run as "$P_g$" into Equation. 4.

Table 2-2 specifies permissible fuel gas temperature and pressure variability to be less than ± 5 $^{o}$F and ± 3.0 percent, respectively. The instruments selected for the verification are capable of providing ± 0.12 $^{o}$F for temperature and ± 0.03 percent for pressure, which is sufficient resolution to measure the actual variability during testing. Both instruments will be factory-calibrated to NIST-traceable standards for accuracy.

#### 2.2.3.6 Ambient Conditions Measurements

Meteorological data will be collected to determine if the maximum permissible limits for determination of electrical efficiency are satisfied. The ambient meteorological conditions (temperature, RH, and barometric pressure) will be monitored using a pressure sensor and an integrated temperature/humidity unit located in close proximity to the air intake of the turbine and the engine.

The integrated temperature/humidity unit uses a platinum 100 Ohm, 1/3 DIN RTD for temperature measurement. As the temperature changes, the resistance of the RTD changes. This resistance change is detected and converted by associated electronic circuitry that provides a linear (DC 4-20mA) output signal.

The unit uses a thin film capacitive sensor for humidity measurement. The dielectric polymer capacitive element varies in capacitance as the RH varies. Internal electronics converts the capacitance change into a linear output signal (DC 4-20 mA). This sensor's electronic compensation maintains accuracy over a broad range of temperature conditions.

The barometric pressure is also measured by a variable capacitance sensor. As pressure increases, the capacitance decreases. The response time of the temperature and humidity sensors is 0.25 seconds and the response time of the pressure sensor is under 2 seconds. The GHG Center's DAS will convert the analog signals to digital format and then store the data as 1-minute averages.

Electrical efficiency determinations require variability in ambient temperature and barometric pressure to be less than the values specified in Tables 2-1 and 2-2. The instruments selected for the verification are capable of providing ± 1.08 $^{o}$F for temperature and ± 0.06 psi for barometric pressure, which is sufficient resolution to measure the actual variability during efficiency testing. The measurement equipment will be factory calibrated to NIST-traceable standards for accuracy.

#### 2.2.3.7 Heat Recovery Rate Measurements

The Controlotron (Model 1010EP1) energy meter is a digitally integrated system that includes a portable computer, ultrasonic fluid flow transmitters, and 1,000 ohm platinum RTDs. The system has an overall rated accuracy of ± 1 to 2 percent of reading depending on location of the RTDs and accuracy of computer programming parameters (e.g., pipe diameter, wall thickness, working fluid composition). The system can be used on pipe or tubing sizes ranging from 0.25 to 360 inches in diameter, with fluid flow rates ranging from 0 to 60 feet per second.

The meter determines fluid velocity be measuring pulse transit times between two ultrasonic transducers. A precision mounting jig secures the transducers to the pipe at a known distance apart. The operator enters the fluid composition, pipe diameter, material, wall thickness, and expected sonic velocity into the heater meter's computer. Then, under zero flow conditions with the pipe full of fluid, the heat meter determines the exact sonic velocity based on the known distance between the transducers. During operation, it multiplies the fluid velocity by the internal area of the pipe to yield volumetric flow rate. The test operator mounts the ultrasonic transducers on the pipe at least ten diameters from upstream and five diameters from the downstream disturbances (e.g., elbows, valves) adjacent to one of the RTDs. The operator enters that RTD's identifier (i.e., supply or return) into the meter software so it can properly calculate heat flow limitation. The RTDs are mounted as close to the heat recovery unit as configuration allows. They provide continuous supply and return fluid line temperatures to the computer, which calculates the temperature difference. The RTDs have a rated differential temperature accuracy of 0.02 $^{o}$F.

Prior to verification, the Field Team Leader will program the following critical parameters into the heat meter's computer:

- pipe diameter or tubing
- wall material and thickness
- distances between ultrasonic transducers
- working fluid composition

The accuracy of these parameters will directly impact the overall accuracy of the meter. The Field Team Leader will obtain pipe or tubing material, exact diameter, and wall thickness from manufacturer specifications. The heat meter includes an alignment bracket, which ensures precise measurement of the distance between transducers. The energy meter software contains lookup tables that provide ASHRAE and ASME working fluid density and specific heat values corrected to the average fluid temperature measured by the RTDs. In order for these values to be correct, the fluid composition must be known or determined, and programmed into the computer. For this verification, pure water will be selected as the heat transfer fluid. The DAS will record 1-minute average fluid flow rate, heat recovery rate, supply temperature, and return temperature.

Several QA/QC procedures will be conducted prior to and during the verification testing to evaluate the accuracy of the meter. These procedures, which include factory calibration of sensors and performance checks in the field, are detailed in Section 3.3.3.

## 2.3 POWER QUALITY PERFORMANCE

When an electrical generator is connected in parallel and operated simultaneously with the utility grid, there are a number of issues of concern. The voltage and frequency generated by the power system must be aligned with the power grid. While in grid parallel mode, the units must detect grid voltage and frequency to ensure proper synchronization before actual grid connection occurs. The generators at the farm accomplish this by converting high-frequency electrical output or adjusting revolutions per minute (rpm) to match the grid frequency and voltage. The microturbine power electronics contain circuitry to detect and react to abnormal conditions that, if exceeded, cause the unit to automatically disconnect from the grid. These out-of-tolerance operating conditions include overvoltages, undervoltages, and over/under frequency. For previous verifications, the GHG Center has defined grid voltage tolerance as the nominal voltage ± 10 percent. Frequency tolerance is 60 ± 0.6 Hz (1.0 percent).

The power factor delivered by each system must be close to unity (100 percent) to avoid billing surcharges. Harmonic distortions in voltage and current must also be minimized to reduce damage or disruption to electrical equipment (e.g., lights, motors, office equipment). Industry standards for harmonic distortion have been established within which power generation equipment must operate.

The generator's effects on electrical frequency, power factor, and total harmonic distortion (THD) cannot be completely isolated from the grid. The quality of power delivered actually represents an aggregate of disturbances already present in the utility grid. For example, local CHP power with low THD will tend to dampen grid power with high THD in the test facility's wiring network. This effect will drop off with distance from the CHP generator.

Synchronous generators usually operate at or near unity (100 percent) power factor. Induction generators, however, always require reactive power from the grid and operate at less than unity power factor. In either case, the generator's power factor effects will also change with distance from the CHP generator as the aggregate grid power factor begins to predominate.

The GHG Center and its stakeholders developed the following power quality evaluation approach to account for these issues. Two documents (IEEE 1992, ANSI/IEEE 1999) form the basis for selecting the power quality parameters of interest and the measurement methods to be used. The GHG Center will measure and record the following power quality parameters for 7 days of operation at normal site conditions:

- Electrical frequency
- Voltage
- Voltage total harmonic distortion
- Current total harmonic distortion
- Power factor

The ION power meter (7600 ION or 7500 ION) used for power output determinations will perform these measurements as described in the following subsections. Prior to field installation, the factory will calibrate the ION power meters to IEC 687 SO.2 and ANSI C12.20 CAO.2 standards. Section 3.2 provides further details about additional QA/QC checks.

### 2.3.1 Electrical Frequency

Electricity supplied in the U.S. and Canada is typically 60 Hz AC. The ION power meters will continuously measure electrical frequency at each generator's distribution panel. The DAS will record 1-minute averages throughout all test periods. The mean frequency is the average of all the recorded 1-minute data over the test period; standard deviation is a measure of dispersion about the mean as follows:

$$F = \frac{\sum_{1}^{n} F_i}{n} \qquad \text{(Eqn. 13)}$$

$$\sigma_F = \sqrt{\frac{\sum_{1}^{n} (F - F_i)^2}{n-1}} \qquad \text{(Eqn. 14)}$$

Where:

F = Mean frequency for baseline and turbine operating periods, Hz

$F_i$ = Average frequency for the ith minute, Hz

n = Number of 1-minute readings logged

$\sigma_F$ = Sample standard deviation in frequency for baseline and turbine operating periods

### 2.3.2 Generator Line Voltage

The CHP unit generates power at 480 Volts (AC). The electric power industry accepts that voltage output can vary within ± 10 percent of the standard voltage (480 volts) without causing significant disturbances to the operation of most end-use equipment. Deviations from this range are often used to quantify voltage sags and surges.

The ION power meter will continuously measure true root mean square (RMS) line-to-line voltage at the generator's distribution panel for each phase pair. True RMS voltage readings provide the most accurate representation of AC voltages. The DAS will record 1-minute averages for each phase pair throughout all test periods. The GHG Center will report voltage data averaged over all three-phase pairs for each test period, consisting of the following output:

- Total number of voltage disturbances exceeding ± 10 percent
- Maximum, minimum, average, and standard deviation of voltage exceeding ± 10 percent
- Maximum and minimum duration of incidents exceeding ± 10 percent

Equations 13 and 14 will be used to compute the mean and standard deviation of the voltage output by substituting the voltage data for the frequency data.

### 2.3.3 Voltage Total Harmonic Distortion

Harmonic distortion results from the operation of non-linear loads. Harmonic distortion can damage or disrupt many kinds of industrial and commercial equipment. Voltage harmonic distortion is any deviation from the pure AC voltage sine waveform.

The ION power meter applies Fourier analysis algorithms to quantify total harmonic distortion (THD). Fourier showed that any wave form can be analyzed as one sum of pure sine waves with different frequencies. He also showed that each contributing sine wave is an integer multiple (or harmonic) or the lowest (or fundamental) frequency. For electrical power in the US, the fundamental is 60 Hz. The 2$^{nd}$ harmonic is 120 Hz, the 3$^{rd}$ is 180 Hz, and so on. Certain harmonics, such as the 5$^{th}$ or 12$^{th}$, can be strongly affected by the types of devices (i.e., capacitors, motor control thyristors, inverters) connected to the distribution network.

For each harmonic, the magnitude of the distortion can vary. Typically, each harmonic's magnitude is represented as a percentage of the RMS voltage of the fundamental. The aggregate effect of all harmonics is called total harmonic distortion (THD). THD amounts to the sum of the RMS voltage of all harmonics divided by the RMS voltage of the fundamental, converted to a percentage. THD gives a useful summary view of the generator's overall voltage quality.

Based on "recommended practices for individual customers" in the IEEE 519 Standard (IEEE 1992), the specified value for total voltage harmonic is a maximum THD of 5.0 percent.

The ION meter will continuously measure voltage THD up to the 63$^{rd}$ harmonic for each phase. The meter's output value is the result of the following calculation:

$$THD_{volt} = \left[ \frac{\sum_{2}^{63} volt_i}{volt_1} \right] * 100 \qquad \text{(Eqn. 15)}$$

Where:
$THD_{volt}$ = Voltage total harmonic distortion, %
$volt_i$ = RMS voltage reading for the ith harmonic, volts
$volt_1$ = RMS voltage reading for the fundamental, volts (220, 480, etc.)

The DAS will record 1-minute voltage THD averages for each phase throughout all test periods. The GHG Center will report periods for which overall voltage THD exceeded 5.0 percent, mean, and standard deviation averaged over all three phases for each test period, per the methods outlined in Equations 13 and 19 above.

### 1.1.1 Current Total Harmonic Distortion

Current THD is any distortion of the pure current AC sine waveform and, similar to voltage THD, can be quantified by Fourier analysis. The current THD limits recommended in the IEEE 519 Standard (IEEE 1992) range from 5 percent to 20 percent, depending on the size of the CHP generator, the test facility's demand, and its distribution network design as compared to the capacity of the local utility grid. For example, the standard's recommendations for a small CHP unit connected to a large capacity grid are more forgiving than those for a large CHP unit connected to a small capacity grid.

Detailed analysis of the facility's distribution network and the local grid are beyond the scope of this verification. The GHG Center will, therefore, report current THD data without reference to a particular recommendation. As with voltage THD, the ION power meter will continuously measure current THD for each phase. The DAS will record 1-minute current THD averages for each phase throughout all test periods. The GHG Center will report mean, and standard deviation of current THD averaged over all three phases for each test period, per the methods outlined in Equations 13 and 14 above.

### 2.3.4 Power Factor

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. Under ideal conditions, current and voltage are in phase, which results in a unity (100 percent) power factor. If reactive loads are present, power factors are less than this optimum value. Although it is desirable to maintain unity power factor, the actual power factor of the electricity supplied by the utility may be much lower because of load demands of different end users. Typical values ranging between 70 and 90 percent are common. Low power factor causes heavier current to flow in power distribution lines for a given number of real kilowatts delivered to an electrical load.

Mathematically, electricity consists of three components, which can be mapped as vectors to form a power triangle: real power (kW), reactive power (kVAr), and apparent power (kVA). Real power is the part of the triangle that results in actual work being performed, in the form of heat and energy. This is the power that is verified in Section 2.2. Reactive power, which accounts for electric and magnetic fields produced by equipment, always acts at right angles, or 90 degrees, to real power.

Real power and reactive power create a right triangle where the hypotenuse is the apparent power, measured in kilovolt-amperes (kVA). The phase angle between real power and apparent power in the power triangle determines the size of the reactive power leg of the triangle. The cosine of the phase angle is called power factor, and is inversely proportional to the amount of reactive power that is being generated. In summary, the larger the amount of reactive power, the lower the power factor will be. Reactive power does not contribute to the system's mechanical or resistive (heat) work, but the conductors still must carry the reactive current. Low power factors require larger capacity equipment and conductors. Low power factors can also exacerbate problems with THD, resonances, and other power quality parameters.

The ION power meter will continuously measure average power factor across each generator phase. The DAS will record one-minute averages for each phase during all test periods. The GHG Center will report maximum, minimum, mean, and standard deviation averaged over all three phases per the methods outlined in Equations 13 and 14 above.

## 2.4 EMISSIONS PERFORMANCE

### 2.4.1 Stack Emission Rate Determination

Exhaust stack emissions testing will be conducted on both CHP systems to determine emission rates for criteria and other pollutants (CO, $NO_X$, $NH_3$, $SO_2$, THCs, and TRS), greenhouse gases ($CH_4$ and $CO_2$), and TPM. Sampling for particulate matter will include quantification of TPM only because the 4-inch diameter engine exhaust stack precludes sampling for $PM_{2.5}$ and $PM_{10}$. The sampling apparatus needed to quantify these parameters is too large to fit into this duct. Using the test procedures presented here, the reported particulate emission rate (TPM) will consist of the sum of emissions of $PM_{2.5}$, $PM_{10}$, and particles larger than $PM_{10}$.

On each of the CHP systems, the stack emission measurements will be conducted simultaneously with electrical power output measurements during load tests. Following NSPS guidelines for evaluation of emissions from stationary gas turbines, exhaust stack emissions testing will be conducted at four loads within the normal operating range of the microturbine and IC engine CHP systems. For the microturbine, test points will include 50, 75, 90, and 100 percent of the normal full load capacity (30 kW). For the engine, 100 percent of rated capacity is not achievable as a result of digester gas production rates. Therefore, the four test points will include the maximum achievable load (approximately 65 kW), the lowest achievable load (approximately 32 kW), and two additional points between this range. Note that emissions testing for $NH_3$, TPM, and TRS will be conducted only at the highest load factor tested on each unit.

The emissions testing will be conducted simultaneously with the efficiency evaluations described in Section 1.5.2. The test matrix and test durations are summarized in Table 1-5. Full load testing on both CHP systems includes emission rate determinations for TPM and $NH_3$. These tests will require approximately 120 minutes to complete because their concentrations are expected to be very low, and longer test duration will increase the method sensitivity. During the microturbine CHP testing, all three full load test replicates for efficiency and gaseous pollutant (each 30 minutes in duration) will be conducted during the first TPM/$NH_3$ test run. The remaining two TPM/$NH_3$ full load test runs will then be conducted at full load before changing load. The same procedure will be followed for the IC engine testing (i.e., finish TPM and $NH_3$ testing after the efficiency testing is completed). Similar test procedures will be followed while the microturbine and IC engine are operated at normal site conditions (Table 1-5).

The average concentrations measured during each test run will be reported in units of ppmvd for CO, $CH_4$, $NO_X$, $NH_3$, $SO_2$, THCs, and TRS, percent for $CO_2$, and grains per dry standard cubic foot (gr/dscf) for TPM. The average emission rates for each pollutant will also be reported in units of pounds per hour (lb/hr), and pounds per kilowatt-hour (lb/kWh). Throughout the testing, operators will maintain process operations to be consistent with the maximum permissible limits presented in Tables 2-1 and 2-2.

An organization specializing in air emissions testing will be contracted to perform all stack testing. The testing contractor will provide all equipment, sampling media, and labor needed to complete the testing and will operate under the supervision of GHG Center Field Team Leader. Table 2-3 summarizes the U.S. EPA Federal Reference Methods from Title 40 CFR 60, Appendix A that will be followed. These Reference Methods are well documented in the Code of Federal Regulations, and are used to determine pollutant levels from a wide variety of sources. They include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations.

| Table 2-3. Summary of Emission Testing Methods | | | | | |
|---|---|---|---|---|---|
| Air Pollutant | Reference Method | Principle of Detection | Proposed Analytical Range[a] | | No. of Test Replicates |
| | | | Microturbine CHP | IC Engine CHP | |
| $CH_4$ | EPA 18 | GC/FID | 0 to 25 ppm | 0 to 500 ppm | 3 per load condition (12 total at controlled load settings and 3 total at normal site conditions |
| CO | EPA 10 | NDIR-Gas Filter Correlation | 0 to 25 ppm | 0 to 500 ppm | |
| $CO_2$ | EPA 3A | NDIR | 0 to 10 % | 0 to 20 % | |
| $NO_X$ | EPA 20 | Chemiluminescence | 0 to 25 ppm | 0 to 250 ppm | |
| $O_2$ | EPA 3A | Paramagnetic | 0 to 25 % | 0 to 25 % | |
| $SO_2$ | EPA 6C | Pulse Fluorescence | 0 to 25 ppm | 0 to 25 ppm | |
| THC | EPA 25A | Flame Ionization | 0 to 25 ppm | 0 to 500 ppm | |
| TRS | EPA 16A | Pulse Fluorescence | 0 to 25 ppm | 0 to 25 ppm | 3 at highest load achievable |
| $NH_3$ | BAAQMD ST-1B | Ion Specific Electrode | 0 to 25 ppm | 0 to 25 ppm | |
| TPM | EPA 5 | Gravimetric | Not specified | | |
| Moisture | EPA 4 | Gravimetric | 0 to 100 % | 0 to 100 % | 3 per load condition (12 total at controlled load settings and 3 total at normal site conditions) |
| Exhaust gas volumetric flow rate | EPA 2C | Pitot Differential Pressure | 250 to 450 scfm | 100 to 200 scfm | 3 per load condition (12 total at controlled load settings and 3 total at normal site conditions) |

[a] Based on previous tests conducted on similar sources, higher analytical ranges may be used at lower operating points.

Each of the selected methods utilizing an instrumental measurement technique includes performance-based specifications for the gas analyzer used. These performance criteria cover span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements. Each test method planned for use is discussed in more detail in the following subsections. The Reference Methods will not be repeated here, but will be available to site personnel during testing. The analytical ranges specified in Table 2-3 may be modified during testing if the proposed ranges are found to be inadequate.

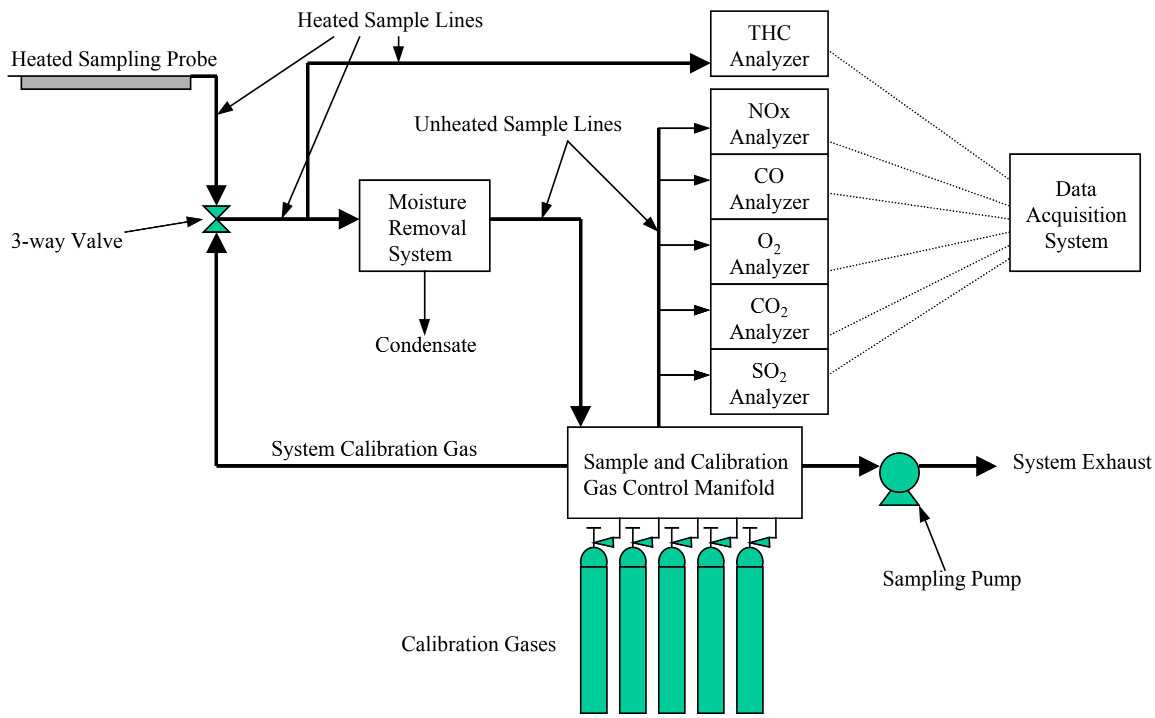
### 2.4.2 Gaseous Sample Conditioning and Handling

A schematic of the sampling system to be used to measure concentrations of CO, $CO_2$, $O_2$, $NO_X$, $SO_2$, and THCs is presented in Figure 2-2. In order for the CO, $CO_2$, $O_2$, $NO_X$, and $SO_2$ measurement instruments to operate properly and reliably, the flue gas must be conditioned prior to introduction into the analyzer. The gas conditioning system is designed to remove water vapor from the sample. All interior surfaces of the gas conditioning system are made of stainless steel, Teflon™, or glass to avoid or minimize any reactions with the sample gas components.

Gas is extracted from the exhaust duct through a stainless steel probe and sample line. The gas is then transported using a sample pump to a gas conditioning system that removes moisture. The clean, dry sample is then transported to a flow distribution manifold where sample flow to each analyzer is controlled. Calibration gases can be routed through this manifold to the sample probe by way of a Teflon line. This allows calibration and bias checks to include all components of the sampling system. The distribution manifold also routes calibration gases directly to the analyzers, where linearity checks are made on each.

The THC analyzer is equipped with a FID. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second, heated sample line is used to deliver unconditioned exhaust gases from the probe to the THC analyzer.

**Figure 2-2. Gaseous Pollutant Sampling System**




### 2.4.3 Gaseous Pollutant Sampling Procedures

This section provides a brief description of the sampling procedures and instrumentation needed to determine concentrations of each of the gaseous pollutants. QA/QC procedures and DQOs for each of these measurements are discussed in Section 3.4.

For $CO_2$ and CO determinations, a continuous sample will be extracted from the emission source and passed through a non-dispersive infrared (NDIR) analyzer (California Analytical Model CA-300P or equivalent). For each pollutant, the NDIR analyzer measures the amount of infrared light that passes through the sample gas versus through the reference cells. Because $CO_2$ and CO absorb light in the infrared region, the degree of light attenuation is proportional to the $CO_2$ and CO concentrations in the sample.

$O_2$ content will also be analyzed with an analyzer using a paramagnetic reaction cell (California Analytical Model CA-300P or equivalent). This analyzer uses a measuring cell that consists of a dumbbell-shaped mass of diamagnetic material, which is electronically temperature controlled to a temperature of 50 $^{o}C$. The higher the sample $O_2$ concentration, the greater the mass is deflected from its rest position. This deflection is detected by an optical system connected to an amplifier. Surrounding the dumbbell is a coil of wire with a current passed through the wire to return the dumbbell to its original position. The current applied is linearly proportional to the $O_2$ concentration in the sample. Exhaust gas $O_2$ concentrations are expected to be 8 to 12 percent for the IC engine and around 18 percent on the microturbine, so the $O_2$ analyzer range will be set at or near 0 to 25 percent.

$NO_X$ will be determined on a continuous basis using a chemilumenescence analyzer (Monitor Labs Model 8840 or equivalent). This analyzer catalytically reduces $NO_X$ in the sample gas to NO. The gas is then converted to excited $NO_2$ molecules by oxidation with $O_3$ (normally generated by ultraviolet light). The resulting $NO_2$ luminesces in the infrared region. The emitted light is measured by an infrared detector and reported as $NO_X$. The intensity of the emitted energy from the excited $NO_2$ is proportional to the concentration of $NO_2$ in the sample. The efficiency of the catalytic converter in making the changes in chemical state for the various $NO_X$ compounds is verified as part of instrument set up and checkout (Section 3.4.1).

An ultraviolet (UV) pulsed fluorescence analyzer will acquire $SO_2$ concentrations (Western Research Model 721, or equivalent). This instrument measures fluorescence from $SO_2$ molecules excited by ultraviolet light.

Concentrations of THC will be measured using a flame ionization analyzer (California Analytical Model 300 AD or equivalent) which passes the sample through a hydrogen flame. The current conducted by the resulting ionization is amplified, measured, and then converted to a signal proportional to the concentration of hydrocarbons in the sample. Unlike the other methods, the sample stream going to the analyzer does not pass through the condenser system, so it must be kept heated until analyzed. This is necessary to avoid loss of the less volatile hydrocarbons in the gas sample by condensation. Because many different hydrocarbons are being analyzed, THC results will be normalized and reported as $CH_4$ equivalent. The calibration gas will be $CH_4$ in $N_2$.

The THC results are measured as parts per million volume (ppmv) on a wet basis, but will be corrected to ppmvd based on exhaust gas moisture measurements made in conjunction with the testing. In conjunction with one of the emissions tests at each load condition, one EPA Reference Method 4 test run will be conducted to quantify the exhaust gas moisture. The results from the Method 4 test run will be used for the moisture correction.

Concentration of $CH_4$ will be determined in accordance with Method 18. Time integrated exhaust gas samples will be collected in evacuated stainless steel canisters. Time integration of samples is accomplished by controlling the flow of gas into the canister with a needle valve or orifice so that the sample is slowly collected over the duration of the test run. Collected samples will be documented in the field and shipped to an analytical laboratory with chain-of-custody records. At the laboratory, samples will be analyzed for $CH_4$ using a gas chromatograph equipped with a FID (GC/FID). Duplicate analyses will be conducted on each sample. The GC/FID will be calibrated prior to sample analyses using certified standards for $CH_4$. Sample canisters will be leak checked by the laboratory prior to testing by evacuating the canisters, allowing the canisters to sit overnight, and recording the final vacuum the next day. Loss of vacuum indicates a leak and the canister will be repaired or rejected.

TRS emissions will be determined using EPA Method 16A. Preliminary fuel samples have demonstrated that $H_2S$ is the only sulfur compound present in the gas in measurable quantities, so results of this testing will represent $H_2S$ emissions from the two CHP systems. During this procedure, a regulated stream of exhaust gas is extracted from a single point near the center of each stack and first passed through a citrate buffer that removes any $SO_2$ that is present in the gas stream. The sample gas is then passed through a combustion tube that oxidizes reduced sulfur compounds to $SO_2$. The $SO_2$ concentrations are then measured using an ultraviolet (UV) pulsed fluorescence analyzer (Western Research Model 721, or equivalent), and reported as ppmvd, $SO_2$.

Emissions of $NH_3$ will be determined using Bay Area Air Quality District (BAAQMD) Method ST-1B. This testing will be incorporated into the TPM sampling train and conducted in conjunction with each TPM test. During each full load test, a regulated stream of exhaust gas is extracted from the stack and directed to a series of impingers containing 0.1N hydrochloric acid (HCl) absorbing solution where. Sample volume is measured using a calibrated dry gas meter. At the conclusion of each test, the impinger solution is collected and returned to a laboratory for analysis. $NH_3$ concentrations in each sample are determined using ion specific electrode procedures.

### 2.4.4 Determination of Emission Rates

The testing for all of the pollutants described above provides results of exhaust gas concentrations in units of percent for $CO_2$ and $O_2$ and ppmvd for CO, $CH_4$, $NO_X$, $NH_3$, $SO_2$, THCs, and TRS. To convert measured pollutant concentrations to mass emissions, exhaust gas flow rate determinations will be conducted during each test run in accordance with EPA Method 2C. Stack gas velocity and temperature traverses will be conducted using a calibrated thermocouple, a standard pitot tube, and an inclined oil manometer. The number and location of traverse points sampled will be selected in accordance with EPA Method 1A due to the small diameters of these stacks. Separate ports will be located downstream of the sampling locations (8 diameters) to allow velocity traversing to occur simultaneously with the sampling. At the conclusion of each test run, stack gas velocity will be calculated using the following equation:

$$v_s = 85.49 * C_p * Avg\left(\sqrt{\Delta p}\right) * \sqrt{\frac{T_s}{P_s M_s}} \qquad \text{(Eqn. 16)}$$

Where:

| | | |
|---|---|---|
| $v_s$ | = | Stack gas velocity, ft/sec |
| $C_p$ | = | Pitot coefficient, dimensionless |
| $Avg\sqrt{\Delta p}$ | = | Average of the square roots of the pitot velocity head as measured at each traverse point, where delta P is in inches of water column |
| $T_s$ | = | Average stack temperature, $^oR$ |
| $P_s$ | = | Absolute pressure in stack, in. Hg |
| $M_s$ | = | Molecular weight of stack gas, lb/lb-mole |

Measured gas velocities will be converted to standard volumetric flow rate using the following equation:

$$Q = 60\,(1 - B_{ws})\,V_s\; A_s \left[\frac{T_{std}\;P_s}{T_{s(abs)}\;P_{std}}\right] \qquad \text{(Eqn. 17)}$$

Where:

| | | |
|---|---|---|
| Q | = | Volumetric flow rate, dscf/min |
| $B_{ws}$ | = | Water vapor in stack gas from Method 4, vol. proportion |
| $V_s$ | = | Stack gas velocity, ft/sec |
| $A_s$ | = | Stack cross sectional area, $ft^2$ |

$T_{std}$ = Standard stack temperature, 528 R
$P_s$ = Stack gas pressure, psia
$T_{s(abs)}$ = Stack temperature, absolute, R
$P_{std}$ = Standard pressure, 14.69 psia

Measured pollutant concentrations as ppmvd will first be converted to pounds per dry standard cubic foot (lb/dscf) using the following unit conversion factors:

$CH_4$: 1 ppmvd = 4.150E-08 lb/dscf
CO: 1 ppmvd = 7.263E-08 lb/dscf
$CO_2$: 1 ppmvd = 1.141E-07 lb/dscf
$NH_3$: 1 ppmvd = 4.409E-08 lb/dscf
$NO_X$: 1 ppmvd = 1.194E-07 lb/dscf $NO_X$ (emissions are quantified as $NO_2$)
$SO_2$: 1 ppmvd = 1.660E-07 lb/dscf
THC: 1 ppmvd = 4.150E-08 lb/dscf THC (emissions are quantified as $CH_4$)
TRS: 1 ppmvd = 1.660E-07 lb/dscf TRS (emissions are quantified as $SO_2$)

After converting measured pollutant concentrations to mass units of lb/dscf, emission rate values will be calculated in units of lb/hr using the standardized volumetric flow rates as follows:

$$ER_{poll} = C_{poll} K_{poll} Q 60 \qquad \text{(Eqn. 18)}$$

Where:
$ER_{poll}$ = Pollutant emission rate, lb/hr
$C_{poll}$ = Average pollutant concentration during the test run, ppmv
$K_{poll}$ = Pollutant ppmvd to lb/dscf (conversion factor see above)
Q = Standard dry volumetric flow rate, dscf/min (Equation 14)
60 = minutes per hour

The mean of the three test results at each load factor will be reported as the average emission rate for that load factor.

Emission rates for each pollutant will then be normalized to system power output to report pollutants in terms of lb/kWh as follows:

$$ER_{norm} = \frac{E_j}{kWh_j} \qquad \text{(Eqn. 19)}$$

Where:
$ER_{norm}$ = Normalized emission rate, lb/kWh
Ej = Mean emission rate at load condition j (Equation 18), lb/hr
$kWh_j$ = Mean power production rate at load condition j

The mean of the three normalized emission rates will be reported as the average emission rate in lb/kWh.

### 2.4.5 Total Particulate (TPM) Emissions Sampling and Analysis procedures

The Method 5 sampling system collects stack gas through a nozzle on a probe inserted in the stack. The test operator adjusts the velocity of the stack gas, which enters the probe to be the same as the stack gas velocity ("isokinetic sampling"). This procedure minimizes inertial effects on the stack gas particulate matter and allows representative sampling. On the 12-inch diameter microturbine exhaust duct, sampling will be conducted at a series of traverse points across the area of the duct, with points selected according to criteria specified in EPA Reference Method 1. On the 4-inch diameter engine exhaust, the method will be modified to incorporate single-point sampling, at a point in the duct of average velocity.

The stack gas and its particulate pass through the heated, glass-lined, probe and through a filter which is maintained at 250 $^oF \pm 25\ ^oF$. The filter collects particulate (usually inorganic matter) which condenses above that temperature; the rest of the stack gas and condensable particulate pass through the filter. The weights of particulate collected on the filter and deposited in the probe and nozzle are correlated with the total volume of stack gas collected and comprises the TPM concentration.

The stack gas then passes into a chilled impinger train charged with 0.1N HCl (used in lieu of distilled water for determination of $NH_3$ emissions). Stack gas moisture and ammonium ion drop out in the impinger train for recovery at the end of the test run. Test operators forward the recovered samples to the laboratory for ammonia analysis. The collected stack gas moisture is correlated with the gas volume for stack gas moisture computation.

TPM concentrations will be calculated as follows:

$$C_{TPM} = \frac{((m_{filter} + m_{probe} - m_{blank})/64.799)}{VM_{std}} \qquad \text{(Eqn. 20)}$$

Where:
$C_{TPM}$ = Particulate mass concentration, gr/dscf
$m_{blank}$ = Total mass of filter and probe rinse blanks, mg
$m_{probe}$ = Mass of particulate collected in probe rinse, mg
$m_{filter}$ = Mass of particulate collected on the filter, mg
$VM_{std}$ = Volume of collected stack gas, corrected to dry standard conditions (68 $^oF$, 29.92 in. Hg), dscf
64.799 = milligrams per grain, mg/gr

Total particulate emission rate will be reported as:

$$E_{TPM,i} = C_{TPM,i} Q 60 \qquad \text{(Eqn. 21)}$$

Where:
$E_{TPM,I}$ = Particulate emission rate, lb/hr
$C_{TPM,I}$ = Mass concentration of particulate matter for run number i (where i = 1 to 3), gr/dscf
Q = Stack dry volumetric flow rate, dscf/min (Equation 17)
60 = minutes per hour

All of the sampling and analytical procedures and reference methods cited here contain QA/QC procedures that will be followed to evaluate data quality. These procedures and data quality goals are detailed in Section 3.4.

## 2.5 ELECTRICITY OFFSETS AND ESTIMATION OF EMISSION REDUCTIONS

This section presents the approach for estimating emission reductions from on-site electric power generation. Emission reductions associated with heat recovery are not planned, as this process requires baseline GHG emission assessment from standard waste management practices. Due to the significant resources required to do this, OEMC has elected to verify emission reductions from electricity generation only.

The GHG Center will first determine emission rates through direct measurements as described in Section 2.4. Those actual emission rates at full load, compared with baseline emissions that would occur if the power generation systems were not in place, form the basis of the emission reduction estimation. Electrical power supplied by the on-site generators will reduce the need for the same amount of electricity from the local grid, after adjusting grid power needs upward to account for transmission line losses. The subtraction of the estimated CHP emissions from the estimated emissions associated with the mix of power stations serving the local grid, will yield an estimate of $CO_2$ and $NO_X$ emission reductions due to grid electricity offset, as shown below.

$$\text{Reduction (lbs)} = E_{CHP} - E_{GRID} \qquad \text{(Eqn. 22)}$$

$$\text{Reduction (\%)} = (E_{GRID}-E_{CHP})/E_{GRID} * 100$$

Where:

| | | |
|---|---|---|
| Reduction | = | Estimated annual emission reductions from on-site electricity generation, lbs or % |
| $E_{CHP}$ | = | Estimated annual emissions from microturbine or IC engine at full load, lbs (Section 2.5.1) |
| $E_{GRID}$ | = | Estimated annual emissions from utility grid, lbs (Section 2.5.2) |

Emission reductions for $CO_2$ and $NO_X$ will be estimated because $CO_2$ is the primary greenhouse gas emitted from combustion processes and $NO_X$ is a primary pollutant of regulatory interest. Reliable emission factors for electric utility grid are available for both gases.

The following subsections describe the approach for estimating emissions for the CHP system and the baseline utility grid.

### 2.5.1 Estimation of $CO_2$ and $NO_X$ Emissions from Microturbine and IC Engine

The first step in calculating emission reductions is to estimate the emissions associated with generating electricity on-site over a given period of time (e.g., 1-week testing). Section 2.4 provided procedures for verifying the emission rates at four operating loads. If each unit is operated at full load, the measured emission rate at full load and the total amount of electrical energy generated during the 1 week of testing at normal site conditions allows the calculation of the CHP system emissions, as shown below:

$$E_{CHP} = ER_{CHP,100\%} * kWh_{CHP} \qquad \text{(Eqn. 23)}$$

Where:
$E_{CHP}$ = Estimated annual emissions from microturbine or engine at full load, lbs (Section 2.4.4)
$ER_{CHP,100\%}$ = Microturbine or engine $CO_2$ or $NO_X$ emission rate at full load, lb/kWh
$kWh_{CHP}$ = Total electrical energy generated at the host site, kWh

### 2.5.2 Estimation of Electric Grid Emissions

The electric energy generated by the microturbine and the IC engine will offset electricity supplied by the grid. Consequently, the reduction in electricity demand from the grid caused by this offset will result in changes in $CO_2$ and $NO_X$ emissions associated with producing an equivalent amount of electricity at central power plants. If the CHP emissions per kWh are less than the emissions per kilowatt-hours produced from an electric utility, it can be implied that a net reduction in emissions will occur at the site. If the emissions from the on-site generators are greater than the emissions from the grid, possibly due to the use of higher efficiency power generation equipment or zero emissions generating technologies (nuclear and hydroelectric) at the power plants, a net increase in emissions may occur.

Utility power systems and regional grids consist of aggregated power typically provided by a wide variety of generating unit (GU) types. Each type of GU emits differing amounts of GHG (and other pollutants) per kilowatt-hours generated. In the simplest case, for a single GU, total $CO_2$ emissions (lb) divided by the total power generated by that GU (kWh) yields the $CO_2$ emission rate for the selected GU (lb/kWh).

More complex analyses require determination of an aggregated baseline emission rate derived from multiple grid-connected GUs. The method to develop an aggregate emission rate is to divide the total emission by the total power generated from the GUs under consideration, as shown for $CO_2$ in Equation 21.

$$ER_{grid} = \frac{\sum_{1}^{n} CO2_n}{\sum_{1}^{n} kWh_n} \qquad \text{(Eqn. 24)}$$

Where:
$ER_{grid}$ = Aggregated baseline grid $CO_2$ emission rate, lb/kWh
$CO2_n$ = Individual $GU_n$ $CO_2$ emissions for the period, lb
$kWh_n$ = Individual $GU_n$ power generated for the period, kWh
n = Number of GU in the baseline selection set

The particular grid-connected GUs chosen for the baseline emission rate calculation have a strong effect on the potential emissions reductions. The microturbine power may offset generation from an individual grid-connected GU or from many GU on a utility-wide, regional, or national basis. Depending on the control system operator, the combination of connected GU can change hourly or less. Some considerations, which may confound the choice of GUs to be offset, are:

- The GU inventory in the geographic region, how they are connected to the grid, local utility fuel mix, and the local dispatch protocol can affect whether or not a particular GU is offset
- Microturbine/engine operating schedules (i.e., in a baseload, peak shaving, or other mode) should be comparable to the offset GU
- Transmission and distribution (T&D) line losses should be considered for the offset GU and for the microturbine if it exports power to the grid
- Several different databases provide emission factor, power generation, cost, and other data in varying formats
- In most cases, real-time electrical production data is not publicly available

If the analyst proposes that GUs that operate on the margin (i.e., those dispatched last and offset first) are to be offset, then marginal fuel prices, dispatchability, and economics at the local and regional level may also need to be considered.

Because of such complex issues, the GHG Center undertook a review of regulatory guidance and industrial community practice on how to choose the grid-connected emissions that would be offset by DG installations. The review included procedures used by the EPA, U.S. Department of Energy (DOE), Western Regional Air Partnership (WRAP), World Resources Institute (WRI), Intergovernmental Panel on Climate Change (IPCC), and other emission trading organizations. The guidance provided by these organizations ranged from vague to explicit and the analyses ranged from simple to complex. Procedures included all levels of refinement from readily available national or regional emission factors to detailed analysis of grid control area boundaries and the GUs therein, hourly operating data, peaks, peak shaving, and/or imports and exports.

After completing the reviews, it was concluded that the method used for choosing the baseline emissions to be offset is arbitrary; clear and consistent guidance does not exist at present. Judgment about whether or not a particular assumption (i.e., selection of a marginal GU to be offset) is reasonable or supportable is subject to opinion and case-by-case review. The strategy the GHG Center has adopted for several DG verifications is to perform analyses using two baselines: 1) national average and 2) local utility which provides electricity to the host site.

The host facility's utility provider is the Southeast Colorado Power Association (SECPA) with headquarters in La Junta, Colorado. Energy Information Administration data (EIA 1999a) indicate that SECPA does not generate any electricity; it distributes and resells utility and non-utility power from other vendors. Because of this, information which could identify specific GUs which would be offset by power generated at the host facility is not publicly available.

This verification, therefore, will compare the microturbine and IC engine emissions to aggregated emission data for the three major types of fossil fuel-fired power plants: coal, petroleum, and natural gas. The GHG Center will employ well-recognized data from DOE and the Energy Information Administration (EIA) for the computations (DOE/EIA 1999b). These data consist of the total emissions and total power generated for each fuel type and are available for the nationwide and Colorado power grids. Total emissions divided by total generated power for each of these geographical regions yields the emission rate in lb/kWh for $CO_2$ and $NO_X$ for each fuel. The emission rate multiplied by the percent power generated by each fuel yields the weighted emission rate, and the sum of the weighted emission rates is the overall emission rate for each region. The following table presents the resulting emission rates for 1999.

The T&D system delivers electricity from the power station to the customer. Power transformers increase the voltage of the produced power to the transmission voltage (generally 115 to 765 kV) and, in turn, reduce it for distribution (25 to 69 kV). Additional transformers reduce the voltage further (to 220 V, 440 V, etc.) at the user's facility. This means that for each kWh used at the host facility (at unity power factor), the grid's generating units must provide additional power to overcome the transformer, powerline, and other losses. EIA data indicate that in 1999, SECPA dispositioned 168,900 MWh of power while 19,283 MWh were lost (EIA 1999a). This equates to a 11.4 percent T&D loss and means that for every kilowatt-hour generated and used by the host facility's CHP, grid-connected generating units would have had to provide 1.114 kWh.

**Table 2-4. $CO_2$ and $NO_X$ Emission Rates for Two Geographical Regions**

| Region | Fuel | Percent of Fossil Fuel Total | $CO_2$ lb/kWh | Weighted $CO_2$ lb/kWh | $NO_X$ lb/kWh | Weighted $NO_X$ lb/kWh |
|---|---|---|---|---|---|---|
| Nationwide | coal | 82.2 | 2.150 | 1.767 | 0.00741 | 0.00609 |
| | petroleum | 4.0 | 1.734 | 0.070 | 0.00283 | 0.00011 |
| | gas | 13.8 | 1.341 | 0.185 | 0.00254 | 0.00035 |
| | | | **Total Weighted $CO_2$ lb/kWh** | **2.022** | **Total Weighted $NO_X$ lb/kWh** | **0.00655** |
| Colorado | coal | 94.0 | 2.193 | 2.061 | 0.00804 | 0.00756 |
| | petroleum | 0.1 | 1.812 | 0.002 | n/a | 0 |
| | gas | 5.9 | 1.114 | 0.066 | 0.00293 | 0.00017 |
| | | | **Total Weighted $CO_2$ lb/kWh** | **2.129** | **Total Weighted $NO_X$ lb/kWh** | **0.00773** |

Power grid emission offsets, therefore, are based on the number of kilowatt-hours generated by the on-site CHP, line losses, and the grid emission rate for $CO_2$ or $NO_X$ as shown in Equation 20.

$$E_{GRID} = kWh_{CHP} * ER_{GRID} * 1.114 \qquad \text{(Eqn. 25)}$$

Where:
$E_{GRID}$ = Grid $CO_2$ or $NO_X$ emissions offset by the CHP, lbs
$kWh_{CHP}$ = CHP power generated, kWh
$ER_{GRID}$ = $CO_2$ or $NO_X$ emission rates from Table 2-4, lb/kWh
1.114 = Total T&D losses

As was discussed in Section 2.5, the GHG Center will use the $E_{GRID}$ estimate to calculate estimated $CO_2$ and $NO_X$ emission reductions according to Equation 22.

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# 3.0 DATA QUALITY

## 3.1 BACKGROUND

The GHG Center selects methodologies and instruments for all verifications to ensure a stated level of data quality in the final results. The GHG Center specifies DQOs for each verification parameter before testing commences as a statement of data quality. Each test measurement that contributes to the determination of a verification parameter has stated DQIs, which, if met, ensure achievement of that parameter's DQO.

The establishment of DQOs begins with the determination of the desired level of confidence in the verification parameters. Table 3-1 summarizes the DQOs for each verification parameter. The next step is to identify all measured values, which affect the verification parameter, and determine the levels of error, which can be tolerated. The DQI goals, most often stated in terms of measurement accuracy, precision, and completeness, are used to determine if the stated DQOs are satisfied.

**Table 3-1. Verification Parameter DQOs**

| Parameter | Total Error[a] | |
|---|---|---|
| | **Absolute** | **Relative, %** |
| **Power and Heat Production Performance** | | |
| Electrical power output at selected loads (kW) | Microturbine: 0.450[b] kW<br>IC Engine: 0.975[c] kW | **1.50** [d] |
| Electrical efficiency at selected loads (%) | Microturbine: 0.42 %<br>IC Engine: 0.41 % | **1.52** [e] |
| Heat recovery rate at selected loads (MMBtu/hr) | Microturbine: 3,284 Btu/hr<br>IC Engine: 5,747 Btu/hr | Microturbine: **1.66** [e]<br>IC Engine: **1.66** [e] |
| Thermal energy efficiency at selected loads (%) | Microturbine: 0.89 %<br>IC Engine: 0.71 % | Microturbine: **1.67** [e]<br>IC Engine: **1.68** [e] |
| CHP production efficiency (%) | Microturbine: 0.98 %<br>IC Engine: 0.82 % | Microturbine: **1.22** [e]<br>IC Engine: **1.18** [e] |
| **Power Quality Performance** | | |
| Electrical frequency (Hz) | 0.006 Hz | **0.01** |
| Voltage | 1.21 V | **1.01**[d] |
| Power factor (%) | TBD | **0.50** |
| Voltage and current total harmonic distortion (THD) (%) | TBD | **1.00** |
| **Emissions Performance** | | |
| CO, $NO_X$, $CO_2$, and $SO_2$ Concentration (ppmv, %) | TBD | **2.0** |
| $CH_4$, NH3, THC, TRS, and TPM Concentration (ppmv) | TBD | **5.0** |
| CO, $NO_X$, $CO_2$ and $SO_2$ Emission Rates (lb/hr) | TBD | **5.59** [e] |
| $CH_4$, $NH_3$, THC, TRS, and TPM Emission Rates (lb/kWh) | TBD | **7.22** [e] |

[a] Bold column entries are DQOs; non-bold column entries are for information purposes
[b] Microturbine: Assumes full load operation 30 kW: 120 V, 250 A
[c] IC Engine: Assumes part load operation 65 kW: 120 V, 540 A
[d] Includes 1.0 % current transformer (CT) and potential transformer (PT) error
[e] Calculated composite error described in text

The following sections describe the data quality assessment process for each verification parameter. This includes a discussion of key measurements that contribute to the determination of the verification parameters, how measurement uncertainties affect their determination, and the resulting DQO. Each section consists of a listing and discussion of DQI goals and QA/QC checks that will be performed to verify the DQI goals are met, and how the DQOs will be reconciled.

## 3.2 ELECTRICAL POWER OUTPUT AND POWER QUALITY

The 7600 ION and 7500 ION power meters will directly determine electrical power output and quality. The two meters' specifications are identical for the measurements considered here. The inherent instrument error constitutes the DQO for each of the verification parameters listed in Table 3-1.

Table 3-2 summarizes the instrument specifications, DQI goals, and the primary method of evaluating the DQI goals achieved for each measurement. Factory calibrations, sensor function checks, and reasonableness checks in the field (listed in Table 3-2) will document achievement of the DQI goals. Some of the QA/QC procedures to be performed are described below.

The power meter manufacturer will issue a certificate of compliance, which certifies that they meet or exceed published specifications. Consistent with ISO 9002-1994 requirements, the manufacturer will supply calibration documents, which certify traceability to national standards. The GHG Center will review the certificate and traceability records to ensure that the ± 0.35 percent accuracy goal was achieved or exceeded. Note that this accuracy standard, compounded with the ± 1.0 percent accuracy specification for the current and potential transformers yields the ± 1.5 percent DQO specified in Table 3-1.

GHG Center personnel will perform checks in the field for two key measurements, voltage and current output, which are directly related to the power output measurement. The Field Team Leader will measure distribution panel voltage and current at the beginning of the verification period. He will use a digital multimeter (DMM) and compare each phase's voltage and current readings to the power meter readings as recorded by the DAS. Appendix A-11 presents the procedures for these checks. The Field Team Leader will obtain a minimum of five individual voltage and current readings for the given load. The power meter voltage and current accuracies are ± 1.01 percent while the DMM is ± 1.0 percent. The percent difference between the DMM reading and the power meter reading will be computed to determine it is within ± 2.01 percent for voltage and current. In these cases, the power meter will be deemed to be functioning properly.

The power meters are intended for electric utility custody transfer applications; their calibration records are reported to be valid for a minimum of 1 year of use, provided the manufacturer-specified installation and setup procedures are followed. GHG Center personnel will perform the related QC checks listed in Table 3-3 and described in detail in Appendices B-1 and B-2. These setup instruction apply to both 7500 and 7600 ION meters. The manufacturer will repeat the factory calibration at the end of the test to ensure that instrument accuracy remain within the specified limits.

Comparisons of the power meter readings as recorded by the GHG Center's DAS with the power output recorded by the microturbine and engine instrumentation will constitute the reasonableness check. At full load, the power meters and machine instruments must indicate between 58.5 and 65 kW for the engine and 27 and 30 kW for the microturbine after derating for elevation differences.

**Table 3-2. Measurement Instrument Specifications and DQI Goals**

| Measurement Variable | | Operating Range Expected in Field | Instrument Type / Manufacturer | Instrument Range | Instrument Rated Accuracy | Frequency of Measurements | Data Quality Indicator Goals: Accuracy[a] | Data Quality Indicator Goals: Completeness | How Verified / Determined |
|---|---|---|---|---|---|---|---|---|---|
| Electrical Power Output and Quality | Power | 0 to 65 kW | Electric Meter/ Power Measurements 7600 ION and 7500 ION | 0 to 260 kW | ± 1.50[c] % reading | once per sec.; DAS records 1 - min averages | ± 1.50 % reading[c] | 100 % for load test periods, 90 % for continuous testing at normal site conditions. | Review manufacturer calibration certificates, Perform sensor function checks in field<br><br>Reasonableness check for voltage, current, and flow computer; field verification of heat meter RTDs |
| | Voltage | 480 V 3 – (phase) ± 10 % | | 0 to 600 V | ± 1.01 % reading | | ± 1.01 % reading | | |
| | Frequency | 60 Hz | | 57 to 63 Hz | ± 0.01 % reading | | ± 0.01 % reading | | |
| | Current | 0 to 200 amps | | 0 to 200 amps | ± 1.01 % reading | | ± 1.01 % reading | | |
| | Voltage THD | 0 to 100 % | | 0 to 100 % | ± 1 % FS | | ± 1 % FS | | |
| | Current THD | 0 to 100 % | | 0 to 100 % | ± 1 % FS | | ± 1 % FS | | |
| | Power Factor | 0 to 100 % | | 0 to 1.0 | ± 0.5 % reading | | ± 0.5 % reading | | |
| Heat Recovery | Heat Recovery Rate | 0 to 510,000 Btu/hr | Controlotron Model 1010WP | Approx. 0 to 5.0 x $10^7$ Btu/hr | ± 2.0 % | | ± 2.0 % | | |
| | Differential Temperature[b] | TBD | | -40 to 250 °F | ± 0.02 °F | | ± 0.02 ° F @ 180 °F | | |
| Ambient Meteorological Conditions | Ambient Temperature[b] | 30 to 90 °F | Vaisala HMD 60Y0 | -40 to 140 °F | ± 1.08 °F | 1 - min averages | ± 1.08 ° F | | Review manufacturer calibration certificates |
| | Relative Humidity[b] | 0 to 100 % | | 0 to 100 % | ± 2 % 0 to 90 % (RH,) ± 3 % 90 to 100 % (RH) | | ± 3 % | | |
| | Ambient Pressure[b] | 28 to 31 in. Hg | SETRA Model 280E or equiv. | 0 to 51 in. Hg | ± 0.11 % FS | | ± 0.11 % FS | | |

(continued)

| Table 3-2. Measurement Instrument Specifications and DQI Goals (continued) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Data Quality Indicator Goals | | |
| **Measurement Variable** | **Operating Range Expected in Field** | | **Instrument Type / Manufacturer** | **Instrument Range** | **Instrument Rated Accuracy** | **Frequency of Measurements** | **Accuracy[a]** | **Completeness** | **How Verified / Determined** |
| Fuel Input | Volumetric Flow Rate | 7 to 26 scfm | Roots Model 2M175 SSM Series B3 | 0 to 30 scfm | ± 1.0 % reading | 5-min. averages | ± 1.0 % reading | 100 % for load tests, 90 % for continuous testing at normal site conditions | Review manufacturer calibration certificates and reasonableness checks |
| | Gas Pressure | 10 to 15 psia | Pressure Transducer / Rosemount 3051 | 0 to 15 psia | ± 0.075 % FS | 1-min. averages | ± 0.075 % FS | | |
| | Gas Temperature | 50 to 90 °F | Rosemount 3095 RTD | 0 to 1,200 °F | ± 0.01 % FS | | ± 0.12 °F | | |
| | LHV | 65 % $CH_4$ 550 to 650 Btu/scf | Gas Chromatograph / HP 589011 | 0 to 100 % $CH_4$ | ± 3.0 % accuracy and ± 0.2 % precision for $CH_4$<br>± 0.1 % repeatability for LHV | Two samples at each condition (i.e., 2 @ 100% power, 2 @ 75% power) | ± 0.2 % for LHV | 100 % for load tests | Repeatability check - duplicate analyses on the same sample |
| | Water Vapor | 5 - 8 % (volume) | Colorimetric Tube / Draeger | 0 - 10 % (volume) | ± 15 % reading | | ± 15 % reading | | |

FS: full-scale
[a] Accuracy goal represents the maximum error expected at the operating range. It is defined as the sum of instrument and sampling errors.
[b] These variables are not directly used to assess DQOs, but are used to determine if DQIs for key measurements are met. They are also used to form conclusions about the system performance.
[c] Includes instrument, 1.0 % current transformer (CT), and 1.0 % potential transformer (PT) errors.

| Table 3-3. Summary of QA/QC Checks | | | | |
|---|---|---|---|---|
| **Measurement Variable** | **QA/QC Check** | **When Performed/Frequency** | **Expected or Allowable Result** | **Response to Check Failure or Out of Control Condition** |
| Power Output | Instrument Calibration by Manufacturer[a] | Beginning and end of test | ± 0.35 % reading | Identify cause of any problem and correct, or replace meter |
| | Sensor Diagnostics in Field | Beginning and end of test | Voltage and current checks within ± 1 % reading | Identify cause of any problem and correct, or replace meter |
| | Reasonableness checks | Throughout test | 27 to 30 kW at full load for microturbine; 65 kW at maximum expected load for engine | Identify cause of any problem and correct or replace meter |
| Fuel Flow Rate | Instrument Calibration by Manufacturer[a] | Beginning and end of test | ± 1.0 % reading | Identify cause of any problem and correct, or replace meter |
| | Reasonableness checks | Throughout test | Microturbine -- Approx. 10.6 scfm at full load; Engine -- Approx. 25.8 scfm at 65 kW | Perform sensor diagnostic checks |
| Fuel Gas Composition and Heating Value | Duplicate analyses performed by laboratory[a] | At least once for each load test and on one blind audit sample | Refer to Tables 3-7 and 3-8 | Repeat analysis |
| | Confirm canister is fully evacuated | Before collection of each sample | canister pressure < 1.0 psia | Reject canister |
| | Calibration with gas standards by laboratory | Prior to analysis of each lot of samples submitted | ± 1.0 % for $CH_4$ | Repeat analysis |
| | Independent performance check with blind audit sample[a] | Two times during test period | ± 3.0 % for each gas constituent | Apply correction factor to sample results |
| Fuel Gas Pressure | Reasonableness check with ambient pressure sensor | Prior to testing | ± 0.2 psia | Identify cause of any problem and correct, or replace meter |
| | Instrument calibration by manufacturer[a] | Prior to testing | ± 0.075 % FS | Identify cause of any problem and correct, or replace meter |
| Fuel Gas Temperature | Instrument calibration by manufacturer[a] | Prior to testing | ± 0.01 % FS or ± 0.12 °F | Identify cause of any problem and correct, or replace meter |
| | Reasonableness check with ambient temperature sensor | At least once during testing | ± 2 °F | Identify cause of any problem and correct, or replace meter |
| Fuel Gas Moisture Content | Duplicate analyses performed by laboratory | At least once for each load test | Difference should be within ± 20 % | Repeat Analysis |

(continued)

| Measurement Variable | QA/QC Check | When Performed/Frequency | Expected or Allowable Result | Response to Check Failure or Out of Control Condition |
|---|---|---|---|---|
| Heat Recovery Rate | Review manufacturer's calibration records for heat meter[a] | Prior to testing | Heat recovery rate: ± 2.0 %<br>Differential Temp: ± 0.02 °F | Recalibrate heat meter |
| | Meter zero check | Prior to testing | Reported heat recovery < 0.5 Btu/min | Recalibrate heat meter |
| | Fluid index check | Each day of testing | ± 5.0 % of reference value | Recalibrate heat meter |
| | Independent performance check of temperature readings | Beginning of test period | Difference between RTD readings < 0.4 °F. Difference between RTD and thermocouple readings < 2.2 °F. | Identify cause of discrepancy and recalibrate heat meter |
| | Reasonableness Check | At least once during test | Difference between DAS and manual calculation < 5 % | Identify discrepancies / recalibrate heat meter |
| Ambient Meteorological Conditions | Instrument calibration by manufacturer or certified laboratory | Beginning and end of test | Temp: ± 1.08 °F<br>Pressure: ± 0.11 % FS<br>RH: ± 3 % | Identify cause of any problem and correct, or replace meter |
| | Reasonableness checks | Once per day during load tests | Recording should be comparable with handheld digital temp/RH meter | Identify cause of any problem and correct, or replace meter |

**Table 3-3. Summary of QA/QC Checks** (continued)

[a] Results of these QA checks will be used to reconcile DQIs

## 3.3 EFFICIENCY

Electrical, thermal, and total CHP system efficiency parameters require determination of electrical power output, recovered heat, and fuel heat input. The efficiency DQOs for microturbine and engine CHP system were presented earlier in Table 3-1. Determination of these errors requires propagation of errors for one or more individual measurements, each with their own characteristic absolute and relative errors. These errors compound into an overall uncertainty for each verification parameter, which is the DQO for that parameter. Errors compound differently, depending on the algebraic operation required for the overall determination (Skoog 1982).

In general, for measurements which are added to or subtracted from each other, their absolute errors compound as follows:

$$err_{c,abs} = \sqrt{err_1^{\,2} + err_2^{\,2}} \qquad \text{(Eqn. 26)}$$

Relative error, then, is:

$$err_{c,rel} = \frac{err_{c,abs}}{Value_1 + Value_2} \qquad \text{(Eqn. 27)}$$

Where:
$err_{c,abs}$ = Compounded error, absolute
$err_1$ = Error in first added value, absolute value
$err_2$ = Error in second added value, absolute value
$err_{c,rel}$ = Compounded error, relative
$value_1$ = First added value
$value_2$ = Second added value

For measurements which are multiplied or divided by each other, their relative errors compound as follows:

$$err_{c,rel} = \sqrt{\left(\frac{err_1}{value_1}\right)^2 + \left(\frac{err_2}{value_2}\right)^2} \qquad \text{(Eqn. 28)}$$

Where:
$err_{c,rel}$ = Compounded error, relative
$err_1$ = Error in first multiplied (or divided) value, absolute value
$err_2$ = Error in second multiplied (or divided) value, absolute value
$value_1$ = First multiplied (or divided) value
$value_2$ = Second multiplied (or divided) value

Table 3-4 applies the concepts summarized in Equations 26 and 28 to estimate the compounded errors in the electrical efficiency. The table includes the contributing measurements, expected measured values, instrument/compounded errors, and reference equations. The resulting DQO is stated as an overall compounded absolute error or relative error in percent.

**Table 3-4. Microturbine Electrical Efficiency Error Propagation Example**

| Measurement | Expected Value | Measurement/Compounded Error | | |
|---|---|---|---|---|
| | | Abs. | Rel. (%) | Operation Type |
| Actual fuel flow rate ($V_g$) | 2.1 acfm | 0.21 acfm | 1.00 | Measurement error |
| Fuel gas pressure ($P_g$) | 55.0 psia | 0.27 psia | 0.005 | Measurement error |
| Fuel gas temperature ($T_g$) | 100 $^oF$ | 0.12 $^oF$ | 0.0013 | Measurement error |
| Comp. factor @ standard conditions (Zstd) | 0.997 | 0.00199 | 0.20 | Measurement error |
| Comp. factor @ actual conditions (Zg) | 0.992 | 0.00198 | 0.20 | Measurement error |
| *Fuel flow rate @ standard conditions (V)* | *7.32 scfm* | *0.09 scfm* | *1.16* | *Multiplication and Division, Equation 4* |
| Measured moisture content | 0.002 g/l | 0.0005 g/l | 25 | Measurement error |
| Mole fraction water in gas sample ($x_w$) | 2.7 % | 0.08 % | 29 | Addition and Division, Equation 9 |
| LHV, dry | 850 Btu/scf | 1.70 | 0.20 | Measurement error |
| *LHV, wet* | *848 Btu/scf* | *1.91* | *0.23* | *Subtraction and Multiplication, Equation 5* |
| *Heat input (HI)* | *372,172 Btu/hr* | *841* | *0.23* | *Multiplication, Equation 3* |
| *Power Output (kW)* | *30 kW* | *0.45 kW* | *1.50* | *Measurement error* |
| *Electrical Efficiency ($\eta_e$)* | *27.50 %* | *0.42 %* | ***1.52*** [a] | *Multiplication, Equation 2* |

[a] DQO for electrical efficiency

The DQI goals listed in Table 3-2 are directly linked to the achievement of these DQOs because if they are met, the instruments and measurements will achieve the listed accuracies. If each of the listed accuracies is achieved, the DQOs will be achieved in turn. DQIs are established for the power meter, fuel flow meter, temperature and pressure sensors, fuel analyses, and the heat meter (Table 3-2). For the power meter, the QA/QC procedures to be performed to assess achievement of DQI goals were described in Section 3.1, and are not repeated. The following subsections describe the QA/QC procedures for the remaining measurements.

### 3.3.1 Fuel Flow Rate Quality Assurance

Prior to verification testing, the GHG Center will send the Roots gas meters to a laboratory for calibration with NIST - traceable volume provers. The resulting calibration certificates will be traceable to the National Institute for Standards and Technology (NIST); GHG Center personnel will review the calibration to ensure satisfaction of the individual fuel meter specifications listed in Table 3-1 and the ± 1.0 percent accuracy specification for the Roots gas meters.

Independent validation of the Roots meters cannot be performed in line with secondary flow meters. However, based on GHG Center’s experience with testing microturbine and engines, reasonableness checks can be performed reliability by comparing the Roots meter readings with the generator’s indicated power output and fuel requirements. As listed in Table 3-3, the Roots meter on the microturbine should indicate approximately 10.6 scfm of fuel input at full load. For the IC engine, approximately 25.8 scfm fuel is required for 65 kW power output.

### 3.3.2 Fuel Gas Pressure and Barometric Pressure Quality Assurance

The manufacturer will calibrate the Rosemount 3051 fuel gas pressure transducer prior to testing. The resulting calibration certificates will be NIST-traceable; GHG Center personnel will review the calibration to ensure satisfaction of the ± 0.075 percent FS specification. Total pressure at the sensor will be the local barometric station pressure (psia) plus the inches of water column indicated by the inclined manometer (in. $H_2O$ * 0.0361 = psia). Agreement within 0.2 psia will show that the pressure transducer is operating properly.

### 3.3.3 Fuel Gas Temperature and Ambient Temperature Quality Assurance

The manufacturers will calibrate the Omega gas temperature transducers and the Vaisala ambient temperature/RH sensor prior to testing. The resulting calibration certificates will be NIST-traceable. GHG Center personnel will review the calibration to ensure satisfaction of the ± 0.12 °F specification for the gas temperature sensors, and the ± 1.08 $^{o}$F specification for ambient temperature.

As a reasonableness check prior to testing, the GHG Center will compare the sensors' DAS readings with the Vaisala ambient temperature readings while both are exposed to ambient air. Agreement within ± 2 °F will show that the transducer is operating properly.

### 3.3.4 Fuel Analyses Quality Assurance

QA/QC procedures for assessing gas composition data quality include duplicate analyses on at least one sample collected during each test run (designated by the Field Team Leader), review of laboratory instrument calibrations, duplicate analysis of a blind audit gas sample, and confirmation of canister pressure prior to sampling. The primary method of reconciling the accuracy goal for gas composition consists of comparison the laboratory reported values with the audit gas. The method of reconciling the precision goal will be comparisons of duplicate analysis results.

During field testing, the GHG Center will supply one blind/audit gas sample to the laboratory for analysis. The audit gas will be an independent Natural Gas GPA Reference Standard manufactured by Scott Specialty Gases with a certified analytical accuracy of ± 2 percent. The audit gas will be shipped to the test location and the Field Team Leader will collect a canister sample of it immediately after one of the fuel gas samples is collected. He will ship the audit sample to the laboratory with the other fuel samples. The laboratory will analyze the audit sample in duplicate. The GHG Center will compute the average result from the two analyses and will compare the results to the certified concentration of each constituent. Allowable error, which is the sum of the instrument calibration criteria and the analytical accuracy of the audit gas, must be less than ± 3 percent for each gas constituent.

Duplicate analyses must conform to ASTM Specification D1945 repeatability guidelines. These guidelines vary according to the component's concentration as illustrated in Table 3-5. Repeatability is the difference between two successive results obtained by the same operator with the same apparatus under constant operating conditions.

**Table 3-5. ASTM D1945 Repeatability Specifications (ASTM 2001b)**

| Component Concentration mol (%) | Repeatability (absolute difference between 2 results) |
|---|---|
| 0 to 0.1 | ± 0.01 |
| 0.1 to 1.0 | ± 0.04 |
| 1.0 to 5.0 | ± 0.07 |
| 5.0 to 10 | ± 0.08 |
| over 10 | ± 0.1 |

Using these guidelines, and the anticipated ranges of gas component concentrations, Table 3-6 summarizes the target repeatability goals of primary gas components (i.e., components present in concentrations greater than 1 percent) for the duplicate analyses. The average difference between all duplicate results will be used to report the precision achieved.

**Table 3-6. DQIs for Anticipated Component Concentrations**

| Gas Component | Expected Concentration Range mol (%) | Repeatability DQI Goal (absolute difference of 2 results) |
|---|---|---|
| Butane | 0.1 – 0.5 | n/a |
| Ethane | 3.0 – 5.0 | ± 0.08 |
| Heptane/ | < 0.1 | n/a |
| Hexane | < 0.1 | n/a |
| Methane | 90 – 95 | ± 0.2 |
| Pentane | < 0.1 | n/a |
| Propane | 1.0 – 3.0 | ± 0.07 |

Additional QA/QC checks include instrument calibrations and confirmation of canister pressures prior to sampling. The analytical laboratory conducts the calibrations on a weekly basis or whenever equipment changes are made on the instrument with a Natural Gas GPA Reference Standard. ASTM Specification D1945 criteria for calibration states that consecutive analytical runs on the gas standard must be accurate to within ± 1 percent of the certified concentration of each component. The laboratory will be required to submit calibration results for each day samples are analyzed.

The Field Team Leader will check sample canister pressures before collection of each sample to confirm that the canisters were properly evacuated at the laboratory prior to shipment to the site. He will employ an electronic vacuum gauge to measure the absolute pressure in each canister and will record the results on log forms. Any canisters with absolute pressures greater than 1 psi will not be used for sampling.

Following ASTM Specification D3588 guidelines, gas LHV and compressibility factor are calculated based on the gas compositional analysis. The GHG Center will therefore evaluate these parameters' validity based on the compositional analyses. The specification includes the equations that are used to calculate repeatability of the LHV calculations provided the analytical repeatability criteria (Table 3-5) are met. The repeatability expected for duplicate samples is approximately 1.2 Btu/1,000 $ft^3$, or about 0.1 percent. Using input from the oil and gas industry and the GHG Center's experience with these analyses, a conservative DQI goal of ± 0.2 percent is established. If the GHG Center determines that the DQI goal for compositional analyses are met, then it can be deduced that the DQI goal for LHV has been met.

### 3.3.5 Heat Recovery Rate Quality Assurance

To ensure that the heat meter's accuracy requirements are met, the GHG Center will obtain factory calibrations for the flow transducers and RTDs. All calibrations will be NIST-traceable. The meter zero check verifies a zero reading by the meter when the CHP system is not in operation. The energy meter's fluid index check employs the ultrasonic signal transit time to verify the meter installation integrity. The meter's software uses a series of look-up tables to assign a reference transit time signal based on input parameters which includes pipe or tubing specifications and fluid composition. After installation of the meter components, the Field Team Leader will compare the actual transit-time signal to the reference value. Differences between the actual and reference values in excess of 5 percent indicate an installation or programming error and a need for corrective action.

The Field Team Leader will independently verify RTD accuracy. He will remove the RTDs from the fluid pipe and place them in an ice water bath along with thermocouples of known accuracy. Temperature readings from both sensors will be recorded for comparison. He will then repeat the procedure in a hot water bath. If the average differences between the RTD readings and thermocouple readings, when compared, are greater than 2.2 $^{o}$F, the meter RTDs will be sent for re-calibration. If the average difference between the two more sensitive RTD readings is less than ± 0.4 °F, it can be concluded that the data are of good quality. Appendix A-9 contains the field data form.

At least once during the test campaign, the Field Team Leader will manually calculate the expected heat recovery based on the heat meter's front panel $T_1$, $T_2$, and flow rate readings as a reasonableness check. Appendix A-10 contains the field data form.

## 3.4 EMISSION MEASUREMENTS QA/QC PROCEDURES

Air pollutant emissions in pounds per hour divided by the electrical power production rate in kilowatt-hours yields the air pollutant emission rate in pounds per kilowatt-hour (Equation 16). To determine overall emission rate error, several measurement errors must be propagated. For example, the contributing measurements for the $NO_X$ emission rate are stack gas concentration (ppmv converted to lb/dscf), exhaust gas flow rate (dscf/hr), and the total CHP power output (kW). The accumulated errors (i.e., DQIs) are ± 2.0. ± 5.0, and ± 1.5 percent, respectively. Compounding of errors in each of these measurements is similar to the discussion in Section 3.3. The result is an overall ± 5.59 percent relative error in the $NO_X$ pound per kilowatt-hour emission rate. Table 3-1 summarizes the DQOs for all emission measurements.

The DQO may be unattainable for TPM emissions because it is likely that TPM concentrations will be extremely low. In past verifications, the compounded error in TPM emissions was within ± 5 percent, but with extremely low particulate concentrations, the overall uncertainty in emission rates may be much higher due to the limited sensitivity of the gravimetric analyses.

The GHG Center will employ the EPA Reference Methods listed in Table 2-3 to determine emission rates of criteria pollutants and greenhouse gases. Table 3-7 summarizes the instrument type or measurement method, accuracy, and data quality indicator goals for this verification. The Reference Methods specify the sampling methods, calibrations, and data quality checks that must be followed to achieve a data set that meets the DQOs. These procedures ensure the quantification of run-specific instrument and sampling errors and that runs are repeated if the specific performance goals are not met. The GHG Center will assess emissions data quality, integrity, and accuracy through these system checks and calibrations. Specific procedures to be conducted during this test are outlined in the following sections and summarized in Table 3-8. Satisfaction and documentation of each of the calibrations and QC checks will verify the accuracy and integrity of the measurements with respect to the DQIs listed in Table 3-8, and subsequently the DQOs for each pollutant.

### 3.4.1 $NO_x$ Emissions Quality Assurance

$NO_x$ Analyzer Interference Test

In accordance with Method 20, an interference test will be conducted on the $NO_x$ analyzer once before the testing begins. This test is conducted by injecting the following calibration gases into the analyzer:

- CO – 500 ± 50 ppm in balance $N_2$
- $SO_2$ – 200 ± 20 ppm in $N_2$
- $CO_2$ – 10 ± 1 % in $N_2$
- $O_2$ – 20.9 ± 1 %

For acceptable analyzer performance, the sum of the interference responses to all of the interference test gases must be ≤ 2 percent of the analyzer span value. Analyzers failing this test will be repaired or replaced.

$NO_2$ Converter Efficiency Test

The $NO_x$ analyzer converts any $NO_2$ present in the gas stream to NO prior to gas analysis. A converter efficiency test must be conducted prior to beginning the testing. This procedure is conducted by introducing to the analyzer a mixture of mid-level calibration gas and air. The analyzer response is recorded every minute thereafter for 30 minutes. If the $NO_2$ to NO conversion is 100 percent efficient, the response will be stable at the highest peak value observed. If the response decreases by more than 2 percent from the peak value observed during the 30-minute test period, the converter is faulty. A $NO_x$ analyzer failing the efficiency test will be either repaired or replaced prior to testing.

$NO_x$ and THC Sampling System Calibration Error and Drift

The sampling system calibration error test must be conducted prior to the start of the first test on each day of testing the $NO_X$ sampling system. Note that the same procedures must be performed on the THC sampling system. The calibration is conducted by sequentially introducing a suite of calibration gases to the sampling system at the sampling probe, and recording the system response. Calibrations will be conducted on all analyzers using EPA Protocol No. 1 calibration gases. Four $NO_X$, and THC calibration gases are required including zero, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. The maximum allowable error in response to any of the calibration gases is ± 2 percent of span for $NO_X$ and ± 5 percent of span for THC.

At the conclusion of each test the zero and mid-level calibration gases are again introduced to the sampling systems at the probe and the response is recorded. System response is compared to the initial calibration error to determine sampling system drift. Drifts in excess of ± 2 percent for $NO_X$ and ± 3 percent for THC are unacceptable and the test will be repeated.

$NO_X$ Audit Gas

The $NO_X$ analyzer will be operated on a full-scale range of 0 to 25 ppm. It is possible that turbine emissions might be at the low end of the analytical range (5 ppm or less). To evaluate the $NO_X$ sampling system accuracy at low concentrations, the GHG Center will provide an EPA Protocol 1 audit sample. The audit gas will be introduced to the sampling system at the probe tip and a stable system response will be recorded. System error will be calculated as follows:

[(system error percent span) = {system response ppm) / audit gas ppm)] / span} x 100 (Eqn. 29)

### 3.4.2 CO, $CO_2$, $O_2$, and $SO_2$ Emissions Quality Assurance

Calibration Error, System Bias, and Calibration Drift Tests

These calibrations will be conducted to verify accuracy of CO, $CO_2$, $O_2$, and $SO_2$ measurements. The calibration error test is conducted at the beginning of each day of testing. A suite of calibration gases is introduced directly to each analyzer and analyzer responses are recorded. EPA Protocol 1 calibration gases must be used for these calibrations. Three gases will be used for $CO_2$, $O_2$, and $SO_2$ including zero, 40 to 60 percent of span, and 80 to 100 percent of span. Four gases will be used for CO including zero and approximately 30, 60, and 90 percent of span. The maximum allowable error in monitor response to any of the calibration gases is ± 2 percent of span.

Before and after each test, the zero and mid-level calibration gases will be introduced to the sampling system at the probe and the response recorded. System bias will then be calculated by comparing the responses to the calibration error responses recorded earlier. System bias must be less than ± 5 percent of span for each parameter for the sampling system to be acceptable. The pre- and post-test system bias calibrations will also be used to calculate drift for each monitor. Drifts in excess of ± 3 percent will be considered unacceptable and the test will be repeated.

**Table 3-7. Instrument Specifications and DQI Goals for Stack Emissions Testing**

| Measurement Variable | | Instrument Specifications | | | Data Quality Indicators | | |
|---|---|---|---|---|---|---|---|
| | | Instrument Type or Method | Instrument Accuracy[a] | Frequency of Measurements | Overall Sampling System Accuracy | Completeness | How Verified / Determined[b] |
| Microturbine and Engine CHP Emissions | $NO_X$ Concentrations | Chemilumenescense analyzer | ± 1 % FS | 1-minute averages (DAS polls analyzer outputs at 5-second intervals) | ± 2 % FS includes sampling system bias corrections) | 100 % 3 valid runs at each specified load) | Follow EPA Method calibration and system performance check criteria |
| | CO Concentrations | NDIR analyzer | ± 1 % FS | | ± 2 % FS (includes sampling system bias corrections) | | |
| | TRS Concentrations | Pulsed fluorescent analyzer | ± 1 % FS | | ± 5 % FS | | |
| | $NH_3$ Concentrations | Ion chromatograph | ± 1 % FS | | ± 5 % FS | | |
| | $SO_2$ Concentrations | Pulsed fluorescent analyzer | ± 1 % FS | | ± 2 % FS (includes sampling system bias corrections) | | |
| | THC Concentrations | FID analyzer | ± 1 % FS | | ± 5 % FS | | |
| | TPM Concentrations | Gravimetric | ± 0.2 % reading for analytical balance | | ± 1 mg/dscm | | |
| | $CO_2$ / $O_2$ Levels; Stack Gas Molecular Weight | NDIR ($CO_2$) / paramagnetic or equivalent ($O_2$) | ± 1 % FS | | ± 2 % FS (includes sampling system bias corrections) | | |
| | $CH_4$ Concentrations | GC / FID | ± 0.1 % FS | Once per test run | ± 5 % FS | | |
| | Stack Gas Flow Rate | Pitot and Thermocouple | n/a | | ± 5 % FS | | |
| | Water Content | Gravimetric | ± 0.2 % FS (FS = 100 %) | Once per load condition | ± 5 % FS | | |

[a] Instrument accuracy is a function of the selected range or full-scale (FS). See Table 2-3 for a complete list of anticipated instrument ranges.
[b] For a full description, see Table 3-4.

| Table 3-8. Summary of Emissions Testing Calibrations and QC Checks | | | | | |
|---|---|---|---|---|---|
| **Measurement Variable** | | **Calibration/QC Check** | **When Performed/Frequency** | **Expected or Allowable Result** | **Response to Check Failure or Out of Control Condition** |
| Emission Rates | CO, $CO_2$, $O_2$, $SO_2$ | Analyzer calibration error test | Daily before testing | ± 2 % of analyzer span | Repair or replace analyzer |
| | | System bias checks | Before each test run | ± 5 % of analyzer span | Correct or repair sampling system |
| | | Calibration drift test | After each test run | ± 3 % of analyzer span | Repeat test |
| | $NO_X$ | Analyzer interference check<br><br>$NO_2$ converter efficiency | Once before testing begins | ± 2 % of analyzer span<br><br>98 % minimum | Repair or replace analyzer |
| | | $NO_x$ Audit gas | Once before testing begins | ± 2 % of analyzer span | Modify or repair sampling system |
| | | Sampling system calibration error and drift checks | Before and after each test run | ± 2 % of analyzer span | Repeat test |
| | THCs | System calibration error test | Daily before testing | ± 5 % of analyzer span | Correct or repair sampling system |
| | | System calibration drift test | After each test run | ± 3 % of analyzer span | Repeat test |
| | $CH_4$ | Duplicate analysis | Each sample | ± 5 % difference | Repeat analysis of same sample |
| | | Calibration of GC with gas standards by certified laboratory | Immediately prior to sample analyses and/or at least once per day | ± 5 % for each compound | Repeat calibration |
| | TPM | Minimum Sample Volume | after each test run | Corrected Vol. $\geq$ 60.0 dscf | Repeat test run |
| | | Percent Isokinetic Rate | after each test run | 90 % $\leq$ I $\leq$ 110 % | Repeat test run |
| | | Analytical Balance Calibration | Once before analysis | ± 0.0001 g | Repair/replace balance |
| | | Filter and Reagent Blanks | Once during testing after first test run | < 10 % of particulate catch for first test run | Recalculate emissions based on high blank values, all runs; determine actual error achieved |
| | | Dry Gas Meter Calibration | Once before and once after testing | ± 5 % | Recalculate emissions based on high blank values, all runs; determine actual error achieved |
| | | Sampling Nozzle Calibration | Once for each nozzle before testing | ± 0.004 in. | Select different nozzle |
| | TRS | Analyzer calibration error test | Daily before testing | ± 2 % of analyzer span | Repair or replace analyzer |
| | | Dry Gas Meter Calibration | Once before and once after testing | ± 5 % | Recalculate emissions based on high blank values, all runs; determine actual error achieved |

(continued)

| Table 3-8. Summary of Emissions Testing Calibrations and QC Checks (continued) | | | | | |
|---|---|---|---|---|---|
| **Measurement Variable** | | **Calibration/QC Check** | **When Performed/Frequency** | **Expected or Allowable Result** | **Response to Check Failure or Out of Control Condition** |
| Emission Rates | $NH_3$ | Calibration of instrument with $NH_3$ standards | Immediately prior to sample analyses and/or at least once/day | ± 5 % | Repeat calibration |
| | | Dry Gas Meter Calibration | Once before and once after testing | ± 5 % | Recalculate emissions based on whichever meter coefficient yields smallest sample volume; determine actual error achieved |
| | Stack Gas Flow | Pitot Tube Dimensional Calibration / Inspection | Once before and once after testing | See 40CFR60 Method 2, Section 10.0 | Select different pitot tube |
| | | Thermocouple Calibration | Once after testing | ± 1.5 % of average stack temperature recorded during final test run | Adjust average stack temperatures for all test runs; recalculate stack flow rates |

### 3.4.3 $CH_4$, $NH_3$, and TRS Emissions Quality Assurance

GC/FID Calibration for $CH_4$

$CH_4$ samples will be collected and analyzed using a GC/FID following the guidelines of EPA Method 18. The GC/FID will be calibrated prior to sample analysis using certified standards for $CH_4$. The accuracy of the analysis is ± 5 percent. Each analysis includes the following quality assurance procedures outlined in CFR Title 40, Part 60, Subpart GG, Appendix A, Method 18, Section 7.4.4 - Quality Assurance (EPA 1999b).

- Duplicate injection of each sample aliquot with agreement of all injections to within 5 percent of the mean;
- Three point calibration curves based on least-squares regression analysis;
- Calibration curves developed prior to analysis;
- Agreement of all calibration points with the theoretical value to within 5 percent.

After all samples have been analyzed, a mid-point calibration will be performed in triplicate. If the as-analyzed value for any compound detected in the test program does not agree within ± 5 percent of its pretest value, then a full post-test curve will be generated and all concentrations will be based upon the average of the pre- and post-test calibration points.

QA/QC Procedures for TRS Sampling

QA/QC procedures specified in the method will be followed during testing including:

- Pre- and post-test calibration of the dry gas meter used to measure sample volume;
- Pre- and post-test sampling train leak checks;

The $SO_2$ analyzer used to measure TRS concentrations will be calibrated using the calibration error procedures outlined in Section 3.4.2.

QA/QC Procedures for $NH_3$ Sampling

QA/QC procedures specified in the method will be followed during testing including:

- Pre- and post-test calibration of the dry gas meter used to measure sample volume;
- Pre- and post-test sampling train leak checks;
- Collection, submittal, and analysis of a reagent blank.

Before the first test run, test operators will collect an aliquot of each sampling and recovery reagent from the storage containers to be used during testing. They will label these as "Trip Blanks" and analyze them along with other samples.

Collected $NH_3$ samples will be shipped to a laboratory for analysis using an ion chromatograph (IC) equipped with conductivity detector. The IC is calibrated using a series of six internal standards that bracket the expected range of sample concentrations. The analytical system is then challenged with no less than three NIST traceable reference standards to evaluate analytical accuracy. The analysis accuracy must be within ± 5 percent of each of the standards, or the system must be repaired and/or recalibrated.

### 3.4.4 Gas Flow Rate and Particulate Emissions Quality Assurance

Pitot Tube Calibration

Determination of stack gas flow rate includes measurement of exhaust gas concentrations of $O_2$, $CO_2$, and water, velocity differential pressure across a pitot tube, and gas temperature. The GHG Field Team Leader will review $O_2$ and $CO_2$ instrumental analyzer data at the end of each test day. Review criteria will be as described previously for the instrumental analyzers. Stack gas moisture field data will also be reviewed to ensure proper procedures were followed (EPA Method 4).

Emissions test operators will certify that the pitot tubes meet applicable requirements for dimensional accuracy using the design criteria detailed in Method 2. Also in accordance with Method 2 calibration criteria, they will perform pre- and post-test thermocouple calibrations by subjecting the thermocouples used during testing to the average temperature found during testing and comparing the readings to a NIST-traceable reference thermometer. For acceptable results, the thermocouple reading must be within 1.5 percent of the reference thermometer. 40CFR60 Method 2, Section 10.3.1 contains thermocouple calibration procedures.

For a valid TPM sample, the minimum sample volume will be 60 dry standard cubic feet (dscf). The GHG Field Team Leader will review field data sheets for each test run to ensure that the proper sample volume was collected. Particulate matter must be sampled isokinetically; in general, this means that the velocity of the stack gas entering the sampling nozzle must be the same as the surrounding stack gas. Method 5 provides equations for computing the isokinetic sampling rate, I. The results are expressed as a percentage of the ideal rate. For these tests, the allowable variation is 90 percent $\leq I \leq$ 110 percent of the ideal isokinetic sampling rate. Test operators will compute I at the conclusion of each test run, and the GHG Field Team Leader will review the calculation before proceeding with the next test run.

To minimize the possibility of sample contamination, sampling probes must have glass liners. Glass nozzles are preferred, but not required. All nozzles must be dimensionally calibrated; GHG Center personnel will review the calibration data while at the test site.

To minimize variability in the back half analysis, test operators will collect sampling filters, reagents and rinses in a clean environment and as expeditiously as possible. The Field Team Leader will observe these efforts for each test run. He will note the starting and ending times for particulate sample recovery and any problems in the Daily Test Log. Method 5 includes procedures for collecting and analyzing filter and reagent blanks. This Test Plan specifically requires filter and reagent blanks as follows:

Filter Blank

Test operators will install an unused filter into the isokinetic sampling chain and conduct a normal leak check as specified in the Methods. This could be done in conjunction with the sample blank described below. They will recover the filter and analyze it along with the test run filters.

Reagent Blanks

Before the first test run, test operators will collect a 200-ml aliquot of each sampling and recovery reagent from the storage containers to be used during testing. They will label these as “Trip Blanks” and analyze them along with other samples.

Before the first test run, test operators will charge the impinger train with the required sampling reagents. They will conduct a normal leak check as specified in the Methods. This could be done in conjunction with the Filter Blank described above. The sampling train will then be washed and sample recovered as if a normal test run had occurred. The recovered reagents will be labeled as “Sample Blank” including separate labeled bottles for “Probe/nozzle”; “Impinger Water”; “Impinger Acetone”; and “Impinger Methylene Chloride”, and analyzed along with the other samples.

Particulate Data Completeness and Reasonableness

The GHG Field Team Leader will review and initial each field data sheet for each particulate sampling test run for completeness and reasonableness. The individual reference methods detail the data to be collected and the review criteria to be employed, but some points are emphasized here for specific methods.

Method 2c stack initial velocity traverse and cyclonic flow check forms must clearly depict the stack traverse points and cyclonic flow readings at those points. Probes and thermocouples must be uniquely identified and calibration information must be traceable to the probe ID.

Method 4 (moisture content) impinger weight forms must include tare and final impinger weights and the total weight of moisture collected.

Method 5 (particulate sampling) forms must include entries for ambient temperature, stack static pressure, nozzle, probe, dry gas meter, and other sample train ID numbers. Barometric pressure must be noted for local conditions, uncorrected to sea level, and must include statements about the elevation difference between the instrument’s location and the stack sampling location. Calibration information must be traceable to the probe, nozzle, sampling train, and other ID’s. Leak check data must include vacuum (Hg), start reading and end reading of the dry gas meter, and a notation that the sample train conforms to leak check requirements.

All sample containers must be sealed and marked with unique identification numbers, which can be traced to each test run. Test operators will mark the outside of all liquid sample containers with a line at the liquid level contained in the bottle. Laboratory personnel will inspect the marks and note whether any fluid has been lost in transport and handling.

At the conclusion of the first emissions test run, test operators will calculate stack moisture content, molecular weight, velocity, volumetric flow, and percent isokinetic sampling rate. The GHG Center representatives will review the calculations before they authorize the following test runs. Comparison of the field data from the first run with following runs will show if the collected data are reasonable and consistent. These procedures and calibrations will provide documentation that the accuracy of each of the individual measurements conformed to Reference Method specifications. Knowing this, an overall uncertainty of ± 5 percent of reading is assigned for TPM determinations, based on propagation of the sum of the squares of the individual measurement errors (Shigehara 1970).

## 3.5 INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE

The equipment used to collect verification data will be subject to the pre- and post-test QC checks discussed earlier. Before the equipment leaves the GHG Center or analytical laboratories, it will be assembled exactly as anticipated to be used in the field and fully tested for functionality. For example, all controllers, flow meters, computers, instruments, and other sub-components of the measurements system will be operated and calibrated as required by the manufacturer and/or this Test Plan. Any faulty sub-components will be repaired or replaced before being transported to the test site. A small amount of consumables and frequently needed spare parts will be maintained at the test site. Major sub-component failures will be handled on a case-by-case basis (e.g., by renting replacement equipment or buying replacement parts).

The instruments used to make gas flow rate measurements are new, having been purchased for this verification. They will be inspected at the GHG Center's laboratory prior to installation in the field to ensure all parts are in good condition. The equipment used to make gas pressure and temperature, and the GHG Center's Environmental Studies Group maintain ambient measurements. The mass flow meters, temperature, gas pressure, and other sensors will be submitted to the manufacturer for calibration prior to being transported to the test site.

## 3.6 INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES

Natural Gas Reference Standard gases will be used to calibrate the GC used for fuel analyses, and to prepare and blind audit sample for submittal to the laboratory. The concentrations of components in the audit gas are certified within ± 2 percent of the tag value. Copies of the audit gas certifications will be available on-site during testing and archived at the GHG Center.

EPA Protocol gases will be used to calibrate the gaseous pollutant measurement system. Calibration gas concentrations meeting the levels stated in Section 2.4 will either be generated from high concentration gases for each target compound using a dilution system or supplied directly from gas cylinders. Per EPA Protocol gas specifications, the actual concentration must be within ± 2 percent of the certified tag value. Copies of the EPA Protocol gas certifications will be available on-site.

# 4.0 DATA ACQUISITION, VALIDATION, AND REPORTING

## 4.1 DATA ACQUISITION AND STORAGE

Test personnel will acquire the following types of data during the verification:

- Continuous measurements i.e., gas pressure, gas temperature, power output and quality, heat recovery, and ambient conditions, to be collected by the GHG Center's DAS
- Fuel gas composition, heating value, compressibility factor, and moisture content from canister samples collected by the Field Team Leader and submitted to laboratory for analysis
- Volumetric gas flow measurements collected by the Field Team Leader
- Emission measurements data collected by contractor and supervised by the Field Team Leader.

The Field Team Leader will also take site photographs and maintain a Daily Test Log which includes the dates and times of setup, testing, teardown, and other activities.

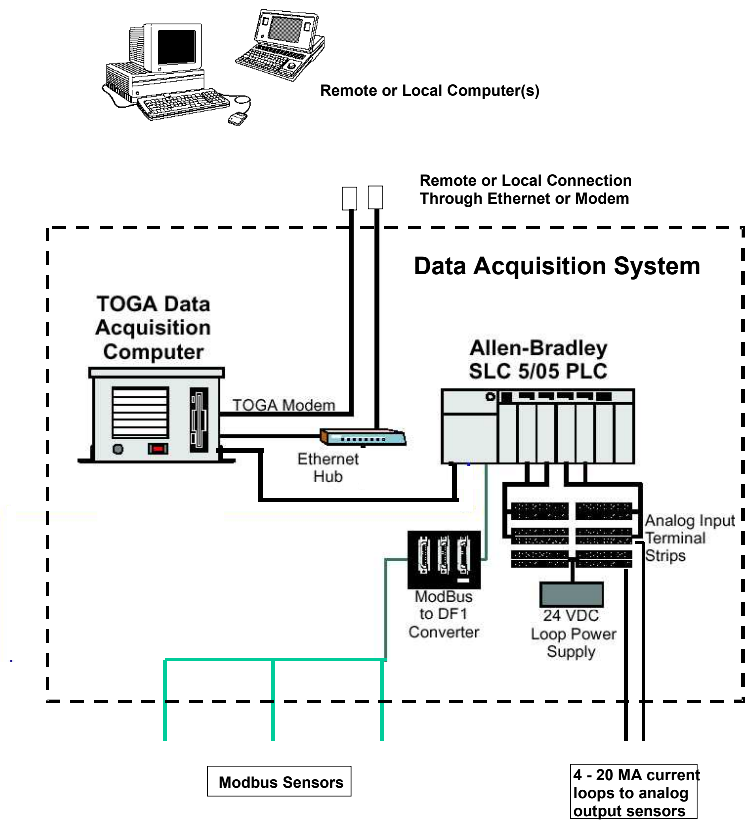
The Field Team Leader will submit digital data files, gas analyses, chain of custody forms, and the Daily Test Log to the Project Manager. The Project Manager will initiate the data review, validation, and calculation process. These submittals will form the basis of the Verification Report which will present data analyses and results in table, chart, or text format as is suited to the data type. The Verification Report's conclusions will be based on the data and the resulting calculations. The GHG Center will archive and store all data in accordance with the GHG Center QMP.

### 4.1.1 Continuous Measurements Data Acquisition

An electronic DAS will collect and store continuous process and ambient meteorological data. Core components of the DAS are an Allen-Bradley (AB) Model SLC 5/05 programmable logic controller (PLC) and a Gladiator Unix-based data acquisition computer data server (TOGA). Figure 4-1 is a schematic of the DAS.

The PLC brings all analog and digital signals from the measurement sensors together into a single real-time data source. The DAS can accommodate any combination of up to 16 analog signal channels with 4 to 20 mA current or DC voltage inputs. Sensors can also provide digital signals *via* the ModBus network to the DF1 interface unit. This converts the ModBus data to the AB "DF1" protocol which is compatible with the PLC. The PLC nominally polls each sensor once per second and converts the signals to engineering units. It then computes 1-minute averages for export to the TOGA and applies a common time stamp to facilitate data synchronization of all measurements.

**Figure 4-1. DAS Schematic**




The TOGA data server records information from the PLC and contains the software for programming the PLC (i.e., data sampling rates, engineering unit conversions, calibration constants). Its UNIX operating system writes all PLC data to a My-SQL relational database for export to spreadsheet, graphics, and other programs. This database is ODBC-compliant, which means that almost any MS Windows program can use the data. The data server includes an external modem and Ethernet card for remote and local communications. During normal operations, the user accesses the data server with a portable laptop or remote computer (PC) *via* its communications port, Ethernet link, or telephone connection. Spreadsheets allow the user to download the entire database or only that portion which has been added since the last download. The user then conducts data queries i.e., for certain times, dates, and selected data columns on the downloaded data as needed.

During the verification testing, GHG Center personnel will configure the DAS to acquire the process variables listed in Table 4-1. Note that the Field Team Leader will acquire the CHP power command and date/time data manually at the start of each test run.

**Table 4-1 Continuous Data to be Collected for Microturbine and IC Engine Evaluation**

| Sensor / Source | Measurement Parameter | Purpose[a] | Significance |
|---|---|---|---|
| Rosemount pressure transducer | Fuel gas pressure (psia) | P | System performance parameter |
| Omega Type K Thermocouple | Fuel gas temperature (°F) | P | System performance parameter |
| Vaisala Model HMP60YO | Ambient temperature (°F) | P | System performance parameter |
| | Ambient relative humidity (% RH) | P | System performance parameter |
| Setra Model 280E | Ambient pressure in (Hg) | P | System performance parameter |
| Electric Meter 7600 ION and 7500 ION | Voltage Output (volts) | P | System performance parameter |
| | Current (amps) | P | System performance parameter |
| | Power factor | P | System performance parameter |
| | Power Output (kW) | P | System performance parameter |
| | Kilovolt-amps reactive | S | System operational parameter |
| | Frequency (Hz) | P | System performance parameter |
| | Voltage THD (%) | P | System performance parameter |
| | Current THD (%) | P | System performance parameter |
| Capstone and Engine Communication System (logged by facility) | Power Command (kW) | P | User input parameter |
| | Date, time | D/S | System operational parameter |
| Controlotron Energy Meter | Temperature of heated liquid exiting heat exchanger (°F) | S | System operational parameter |
| | Temperature of cooled liquid entering heat exchanger(°F) | S | System operational parameter |
| | Liquid flow rate ($ft^3$/min) | S | System operational parameter |
| | Heat recovery rate (Btu/min) | P | System performance parameter |

[a] D = Documentation/diagnostic
P = Primary value: data used in verification
S = Secondary value; used as needed to perform comparisons and assess apparent abnormalities

During field testing, the Field Team Leader will retrieve, review, and validate the electronically collected data at the end of each load testing. To determine if the criteria for electrical efficiency determinations are met, time series power output, power factor, gas flow rate, ambient temperature, and ambient pressure will be processed using the statistical analysis tool in Microsoft Excel®. If it is determined that maximum permissible limits for each variable, meet the variability criteria in Tables 2-1 and 2-2, the electrical efficiency measurement goal will be met. Conversely, the load testing will be repeated until maximum permissible limits are attained. Data for this task will be maintained by computer and by handwritten entries. The Field Team Leader will record manually acquired data (i.e., test run information and observations) in the Daily Test Log and on the log forms in Appendix A. Disk copies of the Excel spreadsheet results will be made at the end of each day. The Field Team Leader will report the following results to the Project Manager:

- Electrical power generated at selected loads
- Gas pressure and temperature at selected loads
- Electrical efficiency at selected loads (estimated until gas analyses results are submitted)
- Heat recovery and use rate at selected loads
- Thermal efficiency at selected loads
- CHP production efficiency

Data quality assurance checks for the instruments illustrated in Figure 2-1 were discussed in Section 3.0. Manual and electronic records (as required) resulting from these checks will be maintained by the Field Team Leader.

After the completion of all test runs, original field data forms, the Daily Test Log, and electronic copies of data output and statistical analyses will be stored at the GHG Center's RTP office per guidelines described in the GHG Center's QMP.

### 4.1.2 Fuel Flow Rate Measurement

Fuel gas flow rate measurement and QA/QC procedures are discussed in Section 2.2.3.3. The Field Team Leader will acquire flow meter at 5-minute intervals. After the test run is completed, the Field Team leader will compute actual volumetric flow rate for each 5-minute interval. The actual flow rate will be corrected to standard conditions using 1-minute average fuel gas temperature and pressure from continuous monitors, and will correspond to the fuel measurements time interval. The mean of all standard gas flow rates will represent the average fuel flow rate for the test run. This value will be used to compute electrical and thermal efficiency.

### 4.1.3 Emission Measurements

The emissions testing contractor will be responsible for all emissions data, QA log forms, and electronic files until they are accepted by the Field Team Leader. For pollutant quantified on-site with analyzers, the emissions contractor will use software to record the concentration signals from the individual monitors. The typical DAS records instrument output at one-second intervals, and averages those signals into 1-minute averages. At the conclusion of a test run, the pre-and post-test calibration results and test run values will be electronically transferred from the tester's DAS into a Microsoft Excel spreadsheet for data calculations and averaging.

The emissions contractor will report emission measurements results to the Field Team Leader as:

- Parts per million by volume (ppmv)
- ppmv corrected to 15 percent $O_2$ (for the microturbine only)
- Emission rate (lb/hr)

Upon completion of the field test activities, the emissions contractor will provide copies of records of calibration, pre-test checks, system response time, $NO_2$ converter flow/efficiency, and field test data to Field Team Leader prior to leaving the site. Testing for $NH_3$, $CH_4$, TRS, and TPM requires analytical procedures that are conducted off-site at a laboratory. The contractor will provide copies of sample chain-of-custody records, analytical data, and laboratory QA/QC documentation for these parameters after field activities are finished. Before leaving the site, the contractor will also provide copies of the field data logs that document collection of each of these samples, as well as QA/QC documentation for the equipment used in collection of these samples (e.g., pitot tubes, gas meters, thermocouples).

A formal report will be prepared by the contractor and submitted to GHG Center Field Team Leader within three weeks of completion of the field activities. The report will describe the test conditions, document all QA/QC procedures, include copies of calibrations, calibration gas, and the certification test results. Field data will be included as an appendix and an electronic copy of the report will be submitted. The submitted information will be stored at the GHG Center's RTP office per guidelines defined in the QMP.

#### 4.1.4 Fuel Gas Sampling

Fuel gas sampling and QA/QC procedures are discussed in Section 2.0. The Field Team Leader will maintain manual fuel sampling logs and chain of custody records. After the field test, the laboratory will submit results for each sample, calibration records, and repeatability test results to the Field Team Leader. Original lab reports and electronic copies of data output and statistical analyses will be stored at the GHG Center's RTP office per guidelines described in the GHG Center's QMP. After receipt of the laboratory analyses, the Field Team Leader will compute the actual electrical and thermal efficiency at each load tested and report the results to the Project Manager.

### 4.2 DATA REVIEW, VALIDATION, AND VERIFICATION

Data review and validation will primarily occur at the following stages:

- On-site -- by the Field Team Leader
- Before writing the draft Verification Report -- by the Project Manager
- During QA review of the draft Verification Report and audit of the data -- by the GHG Center QA Manager

Figure 1-10 identifies the individuals who are responsible for data validation and verification.

The Field Team Leader will be able to review, verify, and validate some data (i.e., DAS file data, reasonableness checks) while on-site. Other data, such as fuel LHV and fuel gas properties, must be reviewed, verified, and validated after testing has ended. The Project Manager holds overall responsibility for these tasks.

Upon review, all collected data will be classed as valid, suspect, or invalid. The GHG Center will employ the QA/QC criteria discussed in Section 3.0; and specified in Tables 3-2, 3-3, and 3-7 through 3-10. Review criteria are in the form of factory and on-site calibrations, maximum calibration and other errors, and audit gas analyses results, and lab repeatability results.

In general, valid results are based on measurements which meet the specified DQIs and QC checks, that were collected when an instrument was verified as being properly calibrated, and that are consistent with reasonable expectations (e.g., manufacturers' specifications, professional judgement).

The data review process often identifies anomalous data. Test personnel will investigate all outlying or unusual values in the field as is possible. Anomalous data may be considered suspect if no specific operational cause to invalidate the data is found.

All data, valid, invalid, and suspect will be included in the Verification Report. However, report conclusions will be based on valid data only and the report will justify the reasons for excluding any data. Suspect data may be included in the analyses, but may be given special treatment as specifically indicated. If the DQI goals cannot be met due to excessive data variability, the Project Manager will decide to either continue the test, collect additional data, or terminate the test and report the data obtained.

The QA Manager will review and validates the data and the draft Verification Report using the Test Plan and test method procedures. The data review and data audit will be conducted in accordance with the GHG Center's QMP. For example, the QA Manager will randomly select raw data and independently calculate the Performance Verification Parameters dependent on that data. The comparison of these calculations with the results presented in the draft Verification Report will yield an assessment of the QA/QC procedures employed by the GHG Center.

## 4.3 RECONCILIATION OF DATA QUALITY OBJECTIVES

A fundamental component of all verifications is the reconciliation of the data and its quality as collected from the field with the DQOs.

In general, when data are collected, the Field Team Leader and Project Manager will review them to ensure that they are valid and are consistent with expectations. They will assess the quality of the data in terms of accuracy and completeness as they relate to the stated DQI goals. Section 3.0 discusses each of the verification parameters and they're contributing measurements in detail. It also specifies the procedures that field personnel will employ to ensure that DQIs are achieved; they need not be repeated here. If the test data show that DQI goals were met, then it will be concluded that DQOs were achieved; DQIs and DQOs will therefore be reconciled. The GHG Center will assess achievement of certain DQI goals during field testing because QC checks and calibrations will be performed on-site or prior to testing. Other DQIs, such as gas analysis repeatability, will be verified after field tests have concluded.

## 4.4 ASSESSMENTS AND RESPONSE ACTIONS

The quality of the project and associated data are assessed by the Field Team Leader, Project Manager, QA Manager, GHG Center Director, and technical peer-reviewers. The Project Manager and QA Manager independently oversee the project and assess its quality through project reviews, inspections if needed, performance evaluation audit (PEA), and an audit of data quality (ADQ).

### 4.4.1 Project Reviews

The review of project data and the writing of project reports are the responsibility of the Project Manager, who also is responsible for conducting the first complete assessment of the project. Although the project's data are reviewed by the project personnel and assessed to determine that the data meet the measurement quality objectives, it is the Project Manager who must assure that project activities meet the measurement and DQO requirements.

The second review of the project is performed by the GHG Center Director, who is responsible for ensuring that the project's activities adhere to the requirements of the program and expectations of the stakeholders. The GHG Center Director's review of the project will also include an assessment of the overall project operations to ensure that the Field Team Leader has the equipment, personnel, and resources to complete the project as required and to deliver data of known and defensible quality.

The third review is that of the QA Manager, who is responsible for ensuring that the program management systems are established and functioning as required by the QMP and corporate policy. The QA Manager is the final reviewer within the SRI organization, and is responsible for assuring that QA requirements have been met.

The draft document will be then reviewed by the OEMC team and selected members of the DG Technical Panel. Technically competent persons who are familiar with the technical aspects of the project, but not involved with the conduct of project activities, will perform the peer-reviews. The peer-reviewers will provide written comments to the Project Manager. Further details on project review requirements can be found in the GHG Center's QMP.

The draft report will then be submitted to EPA QA personnel, and comments will be addressed by the Project Manager. Following this review, the Verification Report and Statement will undergo EPA management reviews, including the GHG Center Program Manager, EPA ORD Laboratory Director, and EPA Technical Editor.

#### 4.4.2 Inspections

Although not planned, inspections may be conducted by the Project Manager or the QA Manager. Inspections assess activities that are considered important or critical to key activities of the project. These critical activities may include, but are not limited to, pre- and post-test calibrations, the data collection equipment, sample equipment preparation, sample analysis, or data reduction. Inspections are assessed with respect to the Test Plan or other established methods, and are documented in the field records. The results of the inspection are reported to the Project Manager and QA Manager. Any deficiencies or problems found during the inspections must be investigated and the results and responses or corrective actions reported in a Corrective Action Report (CAR), shown in Appendix A-14.

#### 4.4.3 Performance Evaluation Audit

Two PEAs are designed to check the operation of the emissions testing analytical system and fuel gas analysis performance by Empact Analytical Laboratory. As discussed in Section 3.0, $NO_X$ gas and fuel gas audit samples, obtained from a gas supplier, will contain analytes at a known concentration. At the invitation of the QA Manager, the Field Team Leader will conduct the PEAs. He will present the audit materials to the emissions testing contractor and Empact Analytical Laboratory in such a manner as to have the concentration of the PEAs unknown or blind to the analyst. Upon receiving the analytical data from the analyst, the Field Team Leader will evaluate the performance data for compliance with the requirements of the project, and report the findings to the QA Manager.

#### 4.4.4 Technical Systems Audit

A Technical Systems Audit (TSA) assesses implementation of Test/QA Plans. Regarding internal TSAs, the Center's QMP specifies that:

> *The Test/QA Plan for each test, or substantially similar group of tests, will be subject of a TSA. This will include field verification in a representative number of tests (at least one per year). Such occasions will be specified in the Test/QA Plan. These will be conducted by SRI's QA staff.*

The current verification is one of five verifications of CHP technologies planned during 2002-2003, several of which are in progress. The intention of the Center is to perform a detailed TSA, including on-site field observation, on one of the earliest of these substantially similar tests, followed by less intensive audits on the remaining tests. These subsequent audits will focus on elements which are unique to the specific tests, and will probably involve interviews and inspection of records rather than field observation. The current verification will receive a TSA in one of these forms.

Since the current schedule of projects suggests that this verification will be one of the first of these substantially similar tests, it is a candidate for the detailed field audit. However, if schedule changes alter the order of the verifications, the "baseline" audit may be performed on another verification, and the TSA for this test will be of the "derivative" or update scope.

### 4.4.5 Audit of Data Quality

The ADQ is an evaluation of the measurement, processing, and data evaluation steps to determine if systematic errors have been introduced. During the ADQ, the QA Manager, or designee, will randomly select approximately 10 percent of the data to be followed through the analysis and data processing. The scope of the ADQ is to verify that the data-handling system functions correctly and to assess the quality of the data generated.

The ADQ, as part of the system audit, is not an evaluation of the reliability of the data presentation. The review of the data presentation is the responsibility of the Project Manager and the technical peer-reviewer.

## 4.5 DOCUMENTATION AND REPORTS

During the different activities on this project, documentation and reporting of information to management and project personnel is critical. To insure the complete transfer of information to all parties involved in this project, the following field test documentation, QC documentation, corrective action/assessment report, and verification report/statements will be prepared.

### 4.5.1 Field Test Documentation

The Field Team Leader will record all important field activities. The Field Team Leader will review all data sheets and maintain them in an organized file. The required test information was described earlier in Sections 2.0 and 3.0. The Field Team Leader will also maintain a daily test log that documents the activities of the field team each day and any deviations from the schedule, Test Plan, or any other significant event. Any major problems found during testing that require corrective action will be reported immediately by the Field Team Leader to the Project Manager through a CAR. The Field Team Leader will document this in the project files and report it to the QA Manager.

The Project Manager will check the test results with the assistance of the Field Team Leader to determine whether the QA criteria were satisfied. Following this review and confirmation that the appropriate data were collected and DQOs were satisfied, the GHG Center Director will be notified.

### 4.5.2 QC Documentation

After the completion of verification test, test data, sampling logs, calibration records, certificates of calibration, and other relevant information will be stored in the project file in the GHG Center's RTP office. Calibration records will include information about the instrument being calibrated, raw calibration data, calibration equations, analyzer identifications, calibration dates, calibration standards used and their traceabilities, calibration equipment, and staff conducting the calibration. These records will be used to prepare the Data Quality section in the Verification Report, and made available to the QA Manager during audits.

### 4.5.3 Corrective Action and Assessment Reports

A corrective action must occur when the result of an audit or quality control measurement is shown to be unsatisfactory, as defined by the DQOs or by the measurement objectives for each task. The corrective action process involves the Field Team Leader, Project Manager, and QA Manager. A written Corrective

Action Report, included in Appendix A-14, is required on major corrective actions that deviate from the Test Plan.

This Test plan includes validation processes to ensure data quality and establishes predetermined limits for data acceptability. Consequently, data determined to deviate from these objectives require evaluation through an immediate correction action process.

Immediate corrective action responds quickly to improper procedures, indications of malfunctioning equipment, or suspicious data. The Field Team Leader, as a result of calibration checks and internal quality control sample analyses, will most frequently identify the need for such an action. The Field Team Leader will immediately notify the Project Manager and will take and document appropriate action. The Project Manager is responsible for and is authorized to halt the work if it is determined that a serious problem exists. The Field Team Leader is responsible for implementing corrective actions identified by the Project Manager, and is authorized to implement any procedures to prevent the recurrence of problems.

The QA Manager will route the ADQ results to the Project Manager for review, comments, and corrective action. The results will be documented in the project records. The Project Manager will take any necessary corrective action needed and will respond by addressing the QA Manger's comments in the final verification Report.

#### 4.5.4 Verification Report and Verification Statement

The Project Manager will coordinate preparation of a draft Verification Report and Statement within 8 weeks of completing the field test, if possible. The Verification Report will specifically address the results of the verification parameters identified in the Test Plan. The GHG Center will prepare separate Verification Reports and Statements for the microturbine CHP and the engine CHP system.

The Project Manager will submit the draft Report and Statement to the QA Manager and Center Director for review. The Report will contain a Verification Statement, which is a 3 to 4 page summary of each CHP technology, the test strategy used, and the verification results obtained. The Verification Report will summarize the results for each verification parameter discussed in Section 2.0 and will contain sufficient raw data to support findings and allow others to assess data trends, completeness, and quality. Clear statements will be provided which characterize the performance of the verification parameters identified in Sections 1.0 and 2.0. A preliminary outline of the report is shown below.

***Preliminary Outline***
***Microturbine and IC Engine Verification Reports***

*Verification Statement*

*Section 1.0:* *Verification Test Design and Description*
*Description of the ETV program*
*Turbine system and site description*
*Overview of the verification parameters and evaluation strategies*

*Section 2.0:* *Results*
*Power production performance*
*Power quality performance*
*Operational performance*
*Emissions performance*

*Section 3.0:* *Data Quality*

*Section 4.0:* *Additional Technical and Performance Data (optional) supplied by the test facility*

*References:*
*Appendices:* *Raw Verification and Other Data*

## 4.6 TRAINING AND QUALIFICATIONS

The GHG Center's Field Team Leader has extensive experience (+15 years) in field testing of air emissions from many types of sources. He is also familiar with natural gas flow measurements from production, processing and transmission stations. He is familiar with the requirements of all of the test methods and standards that will be used in the verification test.

The Project Manager has performed numerous field verifications under the ETV program, and is familiar with requirements mandated by the EPA and GHG Center QMPs. The QA Manager is an independently appointed individual whose responsibility is to ensure the GHG Center's activities are performed according to the EPA approved QMP.

## 4.7 HEALTH AND SAFETY REQUIREMENTS

This section applies to GHG Center personnel only. Other organizations involved in the project have their own health and safety plans - specific to their roles in the project.

GHG Center staff will comply with all known host, state/local and Federal regulations relating to safety at the test facility. This includes use of personal protective gear (e.g., safety glasses, hard hats, hearing protection, safety toe shoes) as required by the host and completion of site safety orientation (i.e., site hazard awareness, alarms and signals).

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# Appendix A

## Test Procedures and Field Log Forms

## Appendix A-1. Load Testing Procedures

1. Enter the load setting, unit controller, nameplate, and other information onto the Load Test Log form.

2. Synchronize all clocks (e.g., test personnel, analyzer) with the DAS time display. Coordinate with emissions testing personnel to establish a test run start time. Record this time on the Load Test Log form.

3. Operate microturbines for a minimum of 0.5 hour during gas analyzer emissions test runs and a minimum of 1 hour for particulate runs. All reciprocating engine test runs are a minimum of 1 hour. Test duration for fuel cells and other technologies varies. Refer to the Test and Quality Assurance Plan for details.

4. For pipeline quality natural gas, obtain a minimum of two (2) fuel gas samples on each day of emissions testing: one immediately before test runs commence, one following their completion. During extended test periods, obtain a minimum of two (2) fuel gas samples per week. Sampling frequency for other fuels (digester gas, etc.) varies. Refer to the Test and Quality Assurance Plan for details.

5. During emissions testing at CHP facilities which use glycol solutions as a heat transfer fluid, obtain a minimum of one (1) glycol sample per day. During extended test periods, obtain a minimum of two (2) glycol samples per week. Heat transfer fluid samples are not required at facilities which use pure water.

6. At the end of each test run, review the data on the Load Test Log form and compare with the maximum permissible variations for microturbines, reciprocating engines, and fuel cells. If the criteria are met, declare an end for the test run. If not, continue operating the unit until the criteria are satisfied. Refer to the Test and Quality Assurance Plan for maximum permissible variations for other technologies.

7. Repeat each emission test run until three (3) valid runs are completed at each of the required load settings.

## Appendix A-2. Load Test Log

Project ID:____________________ Location (city, state):____________________

Date:____________________ Signature:____________________

Unit Description:____________________ Run ID:____________________

Clock synchronization performed (Initials):____________________

| | **Start** | **End** | **Diff** | **% Diff ([Diff/Start]*100)** | **Acceptable? (see below)** |
|---|---|---|---|---|---|
| **Time** | | | | | |
| **Load Setting, kW** | | | | | |
| **Load Setting, %** | | | | | |
| **Actual kW (DAS)** | | | | | |
| **Fuel Flow, scfm** | | | | | |
| **Fuel Gas Pressure, psia** | | | | | |
| **Fuel Gas Temp., $^oF$** | | | | n/a | |
| **Ambient Temp., $^oF$** | | | | n/a | |
| **Ambient Pressure, psia** | | | | | |
| **Heat Recovery Rate, BTU/min** | | | | | |

| **Maximum Permissible Variations** | | | |
|---|---|---|---|
| | **Microturbines (PTC-22)** | **Reciprocating Engines (PTC-17)** | **Fuel Cells (Draft PTC-50)** |
| **Power Output** | ± 2.0 % | ± 3.0 % | ± 2.0 % |
| **Power Factor** | ± 2.0 % | -- | ± 2.0 % |
| **Fuel Flow** | ± 2.0 % | -- | ± 2.0 % |
| **Fuel Gas Pressure** | -- | ± 2.0 % | ± 1.0 % |
| **Fuel Gas Temp.** | -- | -- | ± 3.0 $^oF$ |
| **Inlet/Ambient Temp.** | ± 4.0 % | ± 5.0 $^oF$ | ± 5.0 $^oF$ |
| **Inlet/Ambient Pressure** | ± 0.5 % | ± 1.0 % | ± 0.5 % |

Notes:____________________

## Appendix A-3. Fuel Gas Sampling Procedures

**<u>Important: Follow these procedures when the gas pressure is > 5 psi above atmospheric pressure.</u>**

Collect at least two (2) gas samples during each test condition (i.e., two samples while the microturbine operates at 100 % power, 2 samples at 75 % power, 2 samples during the extended monitoring period).

Attach a leak free vacuum gauge to the sample canister inlet. Open the canister inlet valve and verify that the canister vacuum is at least 15 "Hg. Record the gage pressure on the Fuel Sampling Log form.

Close the canister inlet valve, remove the vacuum gauge, and attach the canister to the fuel line sample port.

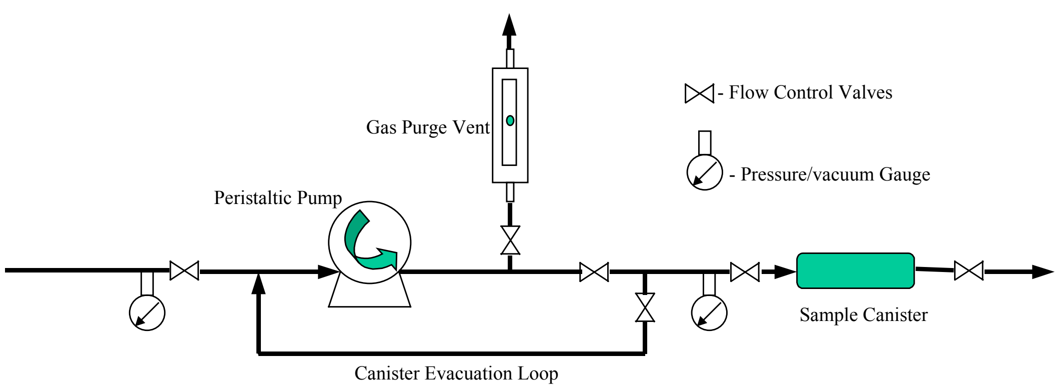
Open the fuel line sample port valve and check all connections for leaks with bubble solution or a hand held analyzer. Repair any leaks, then open the canister inlet valve. Wait five (5) seconds to allow the canister to fill with fuel.

Open the canister outlet valve and purge the canister with fuel gas for at least fifteen (15) but not more than thirty (30) seconds. Close the canister outlet valve, canister inlet valve, and fuel line sampling port valve in that order.

Obtain the fuel gas pressure and temperature from the DAS display. Enter the required information (date, time, canister ID number, etc.) on the Fuel Sampling Log (Appendix A-4a) and Chain of Custody Record (Appendix A-5) forms. Remove the canister from the sampling port.

**<u>Important: Follow these procedures when the gas pressure is < 5 psi above atmospheric pressure.</u>**

Construct a leak free gas extraction and collection system such as shown in the following sketch.




Make a leak free connection from the gas source to the inlet of the gas collection system.

Using the control valves and vacuum gauge, check and record the sample canister vacuum. If necessary, fully evacuate the canister using the peristaltic pump and control valves. Record the final canister vacuum (should be -25 in. Hg or less).

Isolate the evacuated canister and configure the valves so that gas is slowly vented through the purge vent (ensure proper ventilation of gas before starting the purge). Purge for 10 seconds.

(continued)

## Appendix A-3. Fuel Gas Sampling Procedures
(continued)

Close the purge vent, and slowly open the valves upstream of the canister and allow the canister to pressurize to no less than 2 psig.

With the pump still running, open the canister outlet valve and purge the canister for 5 seconds. Sequentially close the canister outlet valve, canister inlet valve, and pump inlet valve. Turn off pump.

Record the date, time, gas temperature (from DAS), canister ID number, and final canister pressure on log form (Appendix A-4b).

Return collected sample(s) to laboratory with completed chain-of-custody form (Appendix A-5).

## Appendix A-4a. Fuel Gas Moisture Sampling Log (High-Pressure Gas)

Project ID:______________________ Location (city, state):____________________________________

Date:____________________ Signature:_____________________________________________

Unit Description:_________________________ Fuel Source (pipeline, digester, etc.)________________

Note: If desired, assign random sample ID numbers to prevent the lab from attributing analysis results to a particular test or audit sample. Transfer sample ID numbers to Chain of Custody Record prior to sample shipment.

Obtain sample pressure and temperature from the DAS display.

| Date | Time | Run ID | Sample ID | Canister ID | Initial Vacuum ("Hg) | Fuel Pressure (DAS) | Fuel Temperature (DAS) |
|---|---|---|---|---|---|---|---|
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Notes:____________________________________________________________________________

## Appendix A-4b. Fuel Gas Moisture Sampling Log
## (Low-Pressure Biogas)

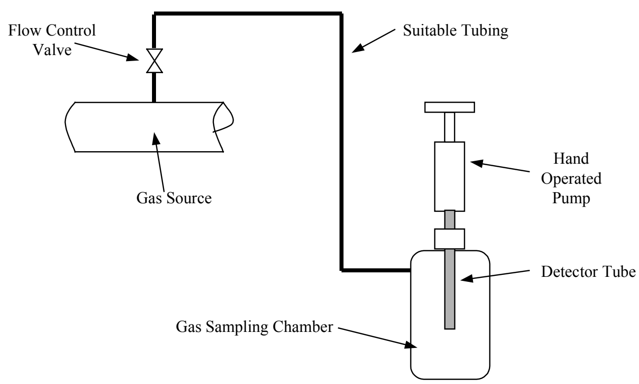
Project ID:______________________ Location (city, state):_________________________________

Date:____________________ Signature:_____________________________________________

Unit Description:_________________________Sampling Location :_____________________________

Pump Type/Volume:_______________________Tube Type/Range:______________________________

Assemble the sampling train as shown below, and follow the sampling procedures.




Procedures:

Make a leak free connection between the hand pump and the gas sampling chamber.

Control gas flow from source using flow control valve and purge the chamber for 1 minute

Connect a fresh detector tube to the pump, insert assembly into chamber, and pump the specified volume of gas through the tube.

Read the moisture content on the tube and record below.

Record the date, time, volume samples, and gas temperature (from DAS display) below.

| Date | Time (24 hr) | Run ID | Sample ID | Gas Temp | Sample Volume | Moisture Content |
|---|---|---|---|---|---|---|
| | | | | | | |
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Notes:_____________________________________________________________________________

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## Appendix A-5. Sample Chain-of-Custody Record

### Southern Research Institute Chain-of-Custody Record

***Important: Use separate Chain-of-Custody Record for each laboratory and/or sample type.***

Project ID:____________________________ Location (city, state):___________________________________

Originator's signature:_________________________________________ Unit description:________________

Sample description & type (gas, liquid, other.):_____________________________________________________

Laboratory:___________________________ Phone:________________ Fax:__________________

Address:______________________________ City:__________________ State:_________ Zip:_____

| Sample ID | Bottle/Canister ID | Sample Pressure | Sample Temp. (°F) | Analyses Req'd |
|---|---|---|---|---|
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Relinquished by:_______________________ Date:__________________ Time:__________________
Received by:___________________________ Date:__________________ Time:__________________

Relinquished by:_______________________ Date:__________________ Time:__________________
Received by:___________________________ Date:__________________ Time:__________________

Relinquished by:_______________________ Date:__________________ Time:__________________
Received by:___________________________ Date:__________________ Time:__________________

Notes: (shipper tracking #, other)________________________________________________________
_____________________________________________________________________________________
_____________________________________________________________________________________
_____________________________________________________________________________________
_____________________________________________________________________________________

## Appendix A-6. Heat Transfer Fluid Sampling Log
## (if other than water)

Project ID:______________________ Location (city, state):___________________________________

Date:____________________ Signature:____________________________________________

Unit Description:_________________________ Sampling Location (supply, return):_________________

Note: If desired, assign random sample ID numbers to prevent the lab from attributing analysis results to a particular test or audit sample. Transfer sample ID numbers to Chain of Custody Record prior to sample shipment.

Obtain sample temperature from the DAS display.

| Date | Time (24 hr) | Run ID | Sample ID | Sample Temp |
|---|---|---|---|---|
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Notes:_________________________________________________________________________________
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_______________________________________________________________________________________
_______________________________________________________________________________________

## Appendix A-7. Fuel Flow Meter Log

1. Start the test run by triggering the stopwatch or timer. Log the initial meter reading at the instant that the stopwatch or timer is triggered. Signal the emission testers and other parties that the test run has commenced.

2. Collect each meter reading by holding the stopwatch or timer next to the meter index. Log the meter reading at the instant that the stopwatch or timer shows the required elapsed time. If a meter reading is missed, collect a reading at the next integer minute. Cross out the missed "elapsed time" entry and note the correct elapsed time in the space provided.

3. Perform all applicable calculations. For the microturbine, determine if all individual hourly flow rates are within ± 2.0 percent of the average hourly flow rate. If any hourly flow rate exceeds this specification, eliminate causes of variability and repeat the test run.

Date:____________ Unit:________________ Run ID:_____________ Load:__________

Meter Model #:__________________________ Serial #:___________________________________

Signature:________________________________________________________________

| **Start Time (24-hr):** | **Meter Reading, $V_I$** | **Diff; $V_{i+1}$-$V_I$** | **Hourly Rate; Diff)*60/$t_i$** |
|---|---|---|---|
| **Elapsed Time (min), $t_i$** | **Init. Mtr. Read., $V_0$** | | |
| **5** | $V_1$ | | |
| **10** | $V_2$ | | |
| **15** | $V_3$ | | |
| **20** | $V_4$ | | |
| **25** | $V_5$ | | |
| **30** | $V_6$ | | |
| **35** | $V_7$ | | |
| **40** | $V_8$ | | |
| **45** | $V_9$ | | |
| **50** | $V_{10}$ | | |
| **55** | $V_{11}$ | | |
| **60** | $V_{12}$ | | |
| | | **Average Hourly Rate** | |
| | | **x 0.02** | |
| | | **Minimum** | |
| | | **Maximum** | |

Notes:__________________________________________________________________

## Appendix A-8. Physical Properties of Water ($lb/ft^3$)

| Air-free Water Interpolated<br>Specific Heat and Density | | |
|---|---|---|
| **Temp. °F** | **Cρ, Btu/lb °F** | **P, $lb/ft^3$** |
| 50 | 1.00129 | 62.41121 |
| 60 | 0.99963 | 62.36739 |
| 70 | 0.99868 | 62.30164 |
| 80 | 0.99816 | 62.21544 |
| 90 | 0.99797 | 62.11353 |
| 100 | 0.99799 | 61.99513 |
| 110 | 0.99817 | 61.86163 |
| 120 | 0.99847 | 61.71324 |
| 130 | 0.99889 | 61.55475 |
| 140 | 0.99943 | 61.38177 |
| 150 | 1.00008 | 61.19551 |
| 160 | 1.00082 | 61.00268 |
| 170 | 1.00172 | 60.79555 |
| 180 | 1.00272 | 60.58212 |
| 190 | 1.00388 | 60.35523 |
| 200 | 1.00517 | 60.12340 |
| 210 | 1.00388 | 59.87843 |
| Source: *CRC Handbook of Chemistry and Physics*, 60th Edition, Robert C. Weast, Ph.D., CRC Press, Boca Raton, FL, 1974. | | |

## Appendix A-9. Heat Meter RTD QA Check

The heat meter receives temperature signals from two resistance temperature devices (RTDs), mounted upstream and downstream of the heat recovery unit. The data acquisition system (DAS) displays and records these temperatures. The GHG Center will evaluate the RTD performance by comparing the DAS displayed temperature values with a calibrated digital thermometer. As calibrated, the accuracy of the digital thermometer is 0.5 percent of reading plus a constant value of 1.3 °F. That is, the accuracy specification is ± 0.5 % Reading ± 1.3 $^{o}$F or ± 2.2 $^{o}$F at 190 $^{o}$F.

GHG Center personnel will conduct the performance check at least once prior to the start of testing as follows:

- 1. Simultaneously immerse the digital thermometer thermocouple and the RTD under test. IMPORTANT: On direct contact RTDs, do not allow the top of the unit (with nameplate and electrical connector) to get wet.
- 2. While stirring, obtain the digital thermometer and DAS readings. Record below.
- 3. Repeat the procedure for hot water and ice baths.
- 4. Compare the RTD DAS readings to the digital thermometer readings. If differences exceed 2.2 $^{o}$F, the RTDs should be submitted for recalibration.

Project ID:____________________ Location (city, state):____________________

Date:____________ Signature:____________________________

---

Digital Thermometer Make:____________ Model:____________ Serial No.________

Thermocouple ID No.____________ Last Calibration Date:____________

Performance Check Location (laboratory or field):__________

Heat Meter Make:____________ Model:____________ Serial No.________

RTD1 Model ________ ID No.________ Type (contact/immersion)________

RTD2 Model ________ ID No.________ Type (contact/immersion)________

---

| Bath Description | RTD1 or RTD2? | RTD DAS Value | Digital Thermometer | Difference | Acceptable ? |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |

## Appendix A-10. Heat Meter Setup and Reasonableness Check

Date:________________________________ Unit:________________________________

Heat Meter Make:______________________ Model #____________________ Serial #:____________________

Signature:________________________________________________________________________________

Enter the following values into the heat meter software:

Pipe or Tubing OD:____________________ Material:_____________ Wall Thickness:_____________

| Nom. Dia | Schedule 40 Steel Pipe | | | Type L Copper Tubing | | |
|---|---|---|---|---|---|---|
| | **Actual OD** | **Wall Thickness** | **Actual ID** | **Actual OD** | **Wall Thickness** | **Actual ID** |
| 1 ¼ | 1.660 | 0.140 | 1.380 | 1.375 | 0.055 | 1.265 |
| 1 ½ | 1.900 | 0.145 | 1.610 | 1.625 | 0.060 | 1.505 |
| 2 | 2.375 | 0.154 | 2.067 | 2.125 | 0.070 | 1.985 |
| 2 ½ | 2.875 | 0.203 | 2.469 | 2.625 | 0.080 | 2.465 |
| 3 | 3.500 | 0.216 | 3.068 | 3.125 | 0.090 | 2.945 |
| 3 ½ | 4.000 | 0.226 | 3.548 | 3.625 | 0.100 | 3.425 |

Source: T. Baumeister, Ed. *Standard Handbook for Mechanical Engineers, 7th Ed*, McGraw Hill, NY, NY 1967

Acquire the following data from the DAS and perform the applicable calculations. Interpolate density and specific heat for $T_{avg}$ from the reference table below or ASHRAE publications.

Date:_________________________ Time (24-Hr):_________________________

DAS $t_1$ ___________

DAS $t_2$ ___________

$t_{avg}$ ___________ $t_1$-$t_2$ _____________

DAS Gal/min ______

$$\frac{(Gal/\min)}{7.4805} = ft^3/\min$$ ____________

DAS Btu/min ______

$C_p$ ______________

$\rho$ _______________

$$Q = V\rho C_p(t_1 - t_2)$$ ______________

Percent Difference: $$\frac{(DAS\,Btu/\min) - Q}{Q} * 100$$ ____________

Acceptable? (< 5 %) (Y/N) ______________

| Reference -- Water Specific Heat and Density | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Temp, °F** | **ρ, lb/ft³** | **$C_p$, Btu/lb.°F** | **Temp, °F** | **ρ, lb/ft³** | **$C_p$, Btu/lb.°F** | **Temp, °F** | **ρ, lb/ft³** | **$C_p$, Btu/lb.°F** |
| 100 | 61.9951 | 0.99799 | 140 | 61.3818 | 0.99943 | 180 | 60.5821 | 1.00272 |
| 110 | 61.8616 | 0.99817 | 150 | 61.1955 | 1.00008 | 190 | 60.3552 | 1.00388 |
| 120 | 61.7132 | 0.99847 | 160 | 61.0027 | 1.00082 | 200 | 60.1234 | 1.00517 |
| 130 | 61.5548 | 0.99889 | 170 | 60.7956 | 1.00172 | 210 | 59.8784 | 1.00388 |

Source: Interpolated from R. Weast, Ed., *CRC Handbook, 60th Ed.*, CRC Press, Inc., Boca Raton, FL. 1979

## Appendix A-11. 7600/7500 ION Installation and Setup Checks

Project ID:____________________ Location (city, state):________________________________________

Date:_________________________ Signature:_________________________________________________

Unit Description:________________________________________________________________________

***IMPORTANT: Conformance to applicable local codes supercede the instructions in this log sheet or the 7600/7500 ION installation manual***

***Only qualified personnel shall install current transformers (CTs) or voltage transformers (PTs). To avoid risk of fire or shock, be sure that the CT shorting switch(es) are installed and operated properly.***

Note: Instructions below pertain to both the 7600-ION and 7500-ION power meters. Initial each item upon completion.

_______ Obtain and read the ION Installation and Basic Setup Manual (manual). It is the source of the items outlined below and is the reference for further questions.

_______ Verify that the ION calibration certificate(s) and supporting data are on hand.

_______ Mount the meter(s) in a well-ventilated location free of moisture, oil, dust, and corrosive vapors. Ensure that all wiring conforms to NEC standards.

_______ Verify that the ION power source is 110 VAC, nominal, protected by a switch or circuit breaker. If used with the DAS, plug the meter into the DAS uninterruptable power supply (UPS).

_______ Connect each ION ground terminal (usually the "Vref" terminal) directly to the switchgear earth ground with a dedicated AWG 12 gauge wire or larger. In most 4-wire WYE setups, jumper the "V4" terminal to the "Vref" terminal. Refer to the manual for specific instructions.

_______ Choose the proper CTs and PTs for the application. Install them in the power circuit and connect them to the ION power meters according to the directions in the manual (pages 8-14).

_______ Trace or color code each CT and PT circuit to ensure that they go to the proper meter terminals. Each CT must match its corresponding PT (i.e. connect the CT for phase A to meter terminals $I_{11}$ and $I_{12}$ and connect the PT for phase A to meter terminals $V_1$ and $V_{ref}$).

_______ Use a digital volt meter (DVM) to measure each phase's voltage and current. Enter the data on the ION Sensor Function Checks form and compare with the ION front panel.

_______ Confirm that the ION front panel readings agree with the DAS display.

_______ Compare the ION and DAS readings to the unit's panel or controller display. Enter this information in the Daily Test Log as is appropriate.

_______ Verify that the DAS is properly logging and storing data by downloading data to the laptop computer and reviewing it.

(continued)

Project ID:______________________________ Location (city, state):______________________________

Date:______________________________ Signature:______________________________

Unit Description:______________________________ Nameplate kW:______________ Expected max. kW:______________

Type (delta, wye):______________________________ Voltage, Line/Line:______________ Line/Neutral:______________

Current (at expected max. kW):______________________________ Conductor type & size:______________________________

Voltage Transformer (PT) Spec. (480/208, other):______________ Current Transformer (CT) Spec. (100:5, 200:5, other):______________

## Sensor Function Checks

Note: Acquire at least five (5) separate readings for each phase. All ION voltage readings must be within 2.01 % of the corresponding DVM reading.

| Voltage | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Date | Time (24 hr) | Phase A | | | Phase B | | | Phase C | | |
| | | ION | DVM | Diff | ION | DVM | Diff | ION | DVM | Diff |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |

Note: Acquire at least five (5) separate readings for each phase. All ION current readings must be within 3.01 % of the corresponding DVM reading.

| Current | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Date | Time (24 hr) | Phase A | | | Phase B | | | Phase C | | |
| | | ION | DVM | Diff | ION | DVM | Diff | ION | DVM | Diff |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
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| | | | | | | | | | | |

## Appendix A-12. ION Sensor Function Checks

Date: ______________________ Project: __________________________________

QA/QC Test Leader Name: ____________________________________________________________

Phase Wiring (Delta or Wye): _____________________________________

**Initial all items after they have been completed.**

_____ 7600 ION calibration certificates and supporting data are on-hand.

_____ Check power supply voltage with a DMM (should be between 85 and 240 VAC.)

_____ Check the 7600 ION ground terminal connection for continuity with the switchgear earth ground.

_____ Use a digital multimeter (DMM) to check that the phase and polarity of the AC voltage inputs are correct.

_____ Verify the operation of the 7600 ION according to the instructions in the *7600 ION INSTALLATION & BASIC SETUP MANUAL* [page 30].

_____ Using a DMM measure the voltage and current for each phase and compare them to the readings on the display of the 7600 ION. The readings on the DMM should agree (within the tolerance of the meters) with the readings from the 7600 ION.

_____ Confirm that the readings on the 7600 ION agree with the corresponding readings on the DAS. If they do not agree, troubleshoot the communications link until proper readings are obtained by the DAS.

_____ Verify that the readings are being properly stored on the DAS hard disk or other non-volatile memory.

| **Load %** | **24-hr Time** | **Voltage, V** | | | | | | **Current, Amps** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Phase A** | | **Phase B** | | **Phase C** | | **Phase A** | | **Phase B** | | **Phase C** | |
| | | **7600 ION** | **DVM** | **7600 ION** | **DVM** | **7600 ION** | **DVM** | **7600 ION** | **DVM** | **7600 ION** | **DVM** | **7600 ION** | **DVM** |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Average** | | | | | | | | | | | | | |
| **% Diff = [(ION-DVM) / ION] * 100** | | | | | | | | | | | | | |

## Appendix A-13 Ambient Monitor Instrument Checks

Note: Route all signal wires away from motors, power mains, or other electrically noisy equipment. Do not use 2-way radios near instruments.

Project ID:______________________________Location (city, state):__________________________

---

### Ambient Pressure Reasonableness Check

Date:________________ Signature:____________________________________________

Site elevation, ft:_______________Source of elevation data:________________________________

Note: Obtain local barometric pressure from airport, National Weather Service, Internet, weather radio, etc. Altitude correction ($Corr_{alt}$) is ≈ 1" Hg per 1000 ft elevation. For exact values, refer to Instruction Booklet for use with Princo Fortin Type Mercury Barometers, http://www.princoinstruments.com/barometers.htm, Table 8, "Pressure Altitude ..."

$P_{bar}$, "Hg:__________ Source of Data:________________________ $Corr_{alt}$, "Hg:________________

$P_{sta}=P_{bar}-Corr_{alt}$ $P_{sta}$, "Hg:___________

$P_{sta}$ * 0.491 = $P_{sta}$, psia:__________DAS Amb. press., psia:__________Difference, psia:___________

Difference should be < 0.2 psia.

---

### Temperature, Relative Humidity Reasonableness Checks

Place Omega temp/RH meter in shade adjacent to the Visala sensor shield.
Compare DAS temperature and relative humidity display to handheld Omega temp/RH meter display.

Date:________________ Signature:____________________________________________

| DAS Temp | Omega Temp | Difference | Acceptable? (within 2 $^oF$) | DAS RH | Omega RH | Difference | Acceptable? (within 8 %) |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | | | | | | |

Notes:________________________________________________________________________

**Appendix A-14. Corrective Action Report**

## Corrective Action Report

Verification Title:________________________________________

Verification Description:____________________________________

Description of Problem:_____________________________________

Originator:____________________ Date:__________

Investigation and Results:__________________________________

Investigator:____________________ Date:__________

Corrective Action Taken:___________________________________

Originator:____________________ Date:__________
Approver:____________________ Date:__________

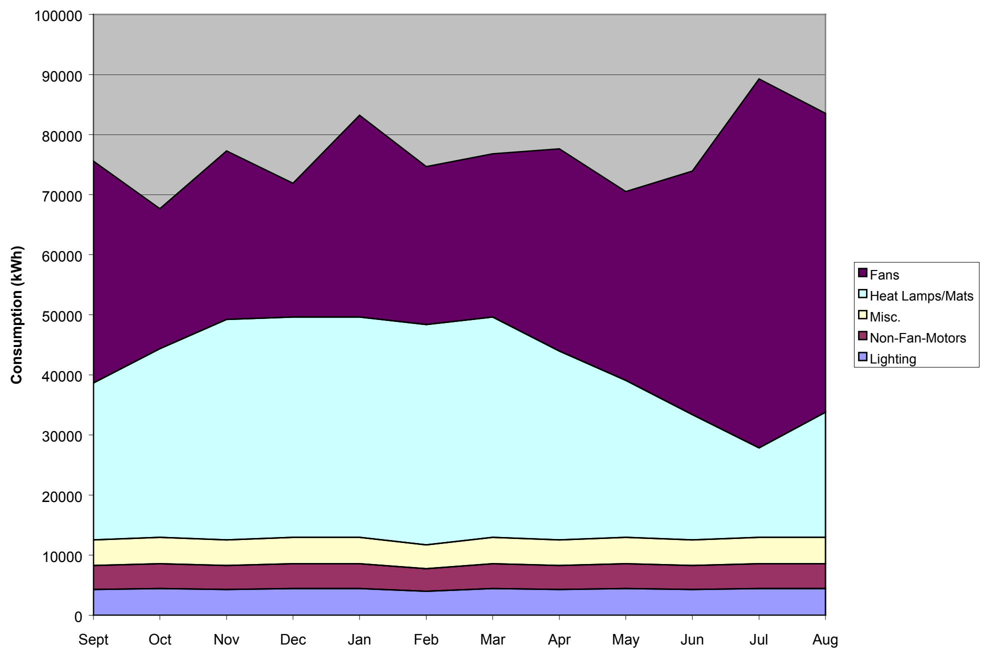
Carbon copy: GHG Center Project Manager, GHG Center Director, SRI QA Manager, APPCD Project Officer

# APPENDIX B

## Appendix B-1. Colorado Pork Electrical and Thermal Energy Demand

The largest electricity consuming equipment at Colorado Pork include: ventilation fans, electric heating mats and lamps used to keep the piglets warm), lighting, and electric motors (excluding fan motors). Figure B-1 shows typical monthly consumption and peak demand, as reported in a recent energy audit report for Colorado Pork.

**Figure B-1. Colorado Pork Electric Consumption and Peak Demand**



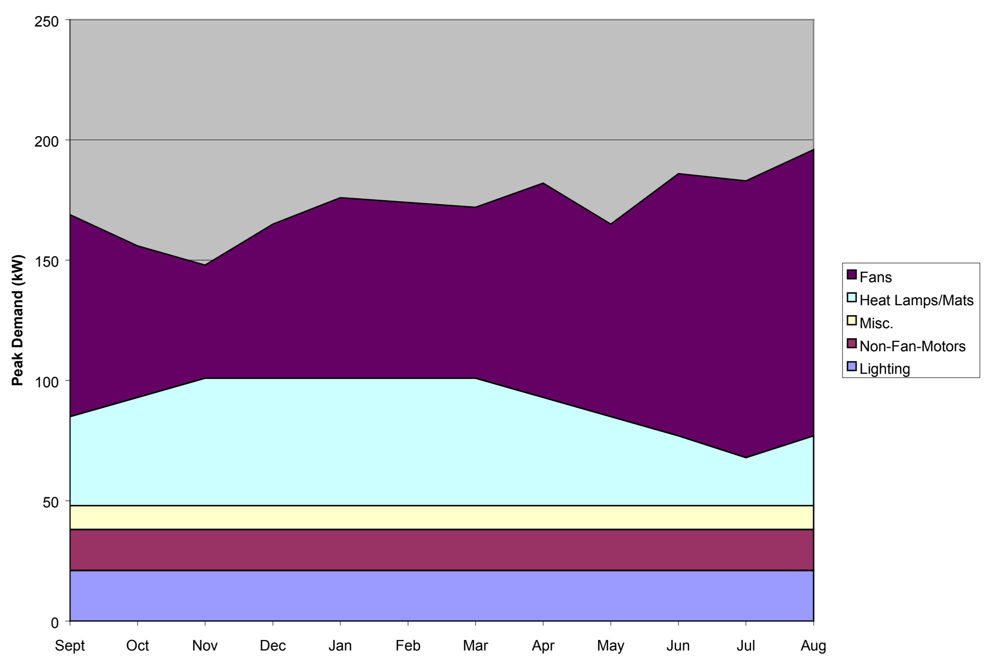



Table B-1 shows 15 months of actual electricity billing records, during which the IC engine system was generating electricity. The peak electricity use and demand months for the site are July and August, when fans are at their highest use for cooling purposes. Average monthly electricity consumption rate is about 71 MWh or an average load of 100 kW. Of this amount, 56 kW was purchased from the utility. The site pays about $0.04/kWh for this electricity. The IC engine system generated on average, 44 kW electric power on biogas in addition to the 56 kW purchased from the utility. This indicates that capacity for additional on-site power generation exists, and significant opportunity for cost reduction could occur if electricity purchased is further reduced with the use of additional on-site generation capacity (i.e., increased power output from IC engine and/or operate a microturbine system). The IC engine operational availability is reported to be 92 percent; however, extended downtimes in some months resulted in increased electricity purchases.

In addition to the electricity charges, the site pays $12.25/kW demand charge for peak power. The site's peak demand, defined as the maximum kilowatt demand for any 15-minute period in a billing month, was 120 kW for the past 15 months. The peak demand charges were higher during engine down periods. Because of the peak demand charge, on-site generation systems may help reduce demand costs if their run times can be scheduled to match peak facility demand periods. Such benefits require that the generator and/or microturbine do not go down for any given 15 minutes when the facility is at peak demand, or the site will be billed for that demand level for the entire month.

**Table B-1. Electricity Purchase and Generation**

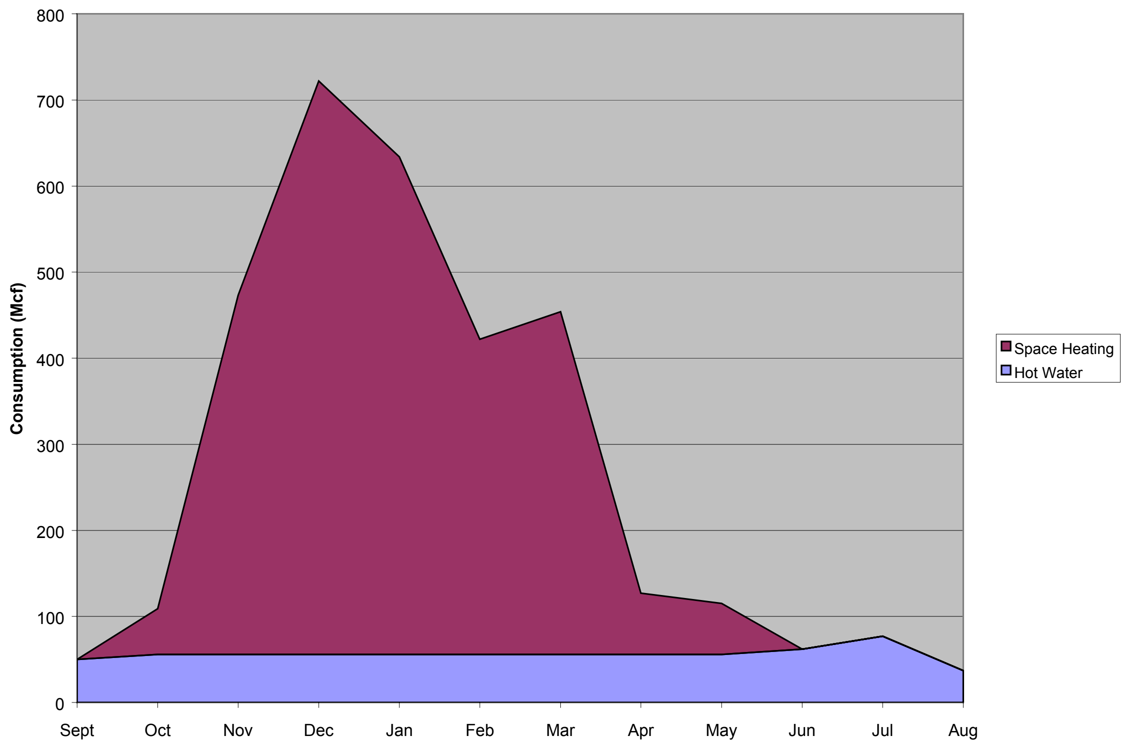
| | | Total Purchase | | Total Generation – IC Engine | | Peak Demand Charged by Utility |
|---|---|---|---|---|---|---|
| **Billing Period ending data (mm/dd/yy)** | **Month** | **(kWh)** | **(kW)** | **(kWh)** | **(kW)** | **(kW)** |
| 1/19/00 | Jan | 22,560 | 30.32 | 33,964 | 50.00 | 80.96 |
| 2/17/00* | Feb | 20,280 | 30.18 | 37,539 | 59.00 | 108.20 |
| 3/17/00* | Mar | 37,760 | 50.75 | 25,692 | 54.00 | 125.86 |
| 4/14/00 | Apr | 19,320 | 26.83 | 40,272 | 58.00 | 91.60 |
| 5/16/00 | May | 22,360 | 30.05 | 28,924 | 37.00 | 110.12 |
| 6/16/00* | Jun | 50,880 | 70.67 | 14,045 | 25.00 | 135.16 |
| 7/20/00* | Jul | 62,840 | 84.46 | 24,350 | 37.00 | 160.68 |
| 8/24/00* | Aug | 60,760 | 81.67 | 30,959 | 45.00 | 130.48 |
| 9/21/00* | Sep | 41,280 | 57.33 | 34,296 | 47.00 | 122.28 |
| 10/19/00 | Oct | 37,560 | 50.48 | 30,122 | 42.00 | 114.00 |
| 11/21/00 | Nov | 51,000 | 70.83 | 26,287 | 37.00 | 111.36 |
| 12/18/00* | Dec | 46,560 | 62.58 | 25,334 | 36.00 | 129.34 |
| 1/18/01 | Jan | 51,760 | 69.57 | 31,457 | 43.00 | 132.92 |
| 2/20/01* | Feb | 45,960 | 68.39 | 28,711 | 48.00 | 126.48 |
| 3/20/01 | Mar | 45,920 | 61.72 | 30,880 | 46.00 | 126.36 |
| | | | | | | |
| **Average** | | **41,120** | **56.39** | **29,522** | **44.27** | **120.39** |

* Indicates the downtime for IC engine was greater than 5 percent of total available hours in the month.

Space heating and water heating are the two major natural gas users. As shown in Figure B-2, natural gas consumption rate for domestic hot water heaters is relatively constant (56 Mcf). During winter months, colder temperatures result in a significant increase in natural gas consumption for space heating use (~400

Mcf). Using a standard heating value of natural gas (850 Btu/cf), it is estimated that the continuous heat load of the site is 66,000 Btu/hr, and maximum heat load is 852,000 Btu/hr for winter months. This does not include the heat required to maintain the digester at 105 °F.

**Figure B-2. Colorado Natural Gas Consumption**

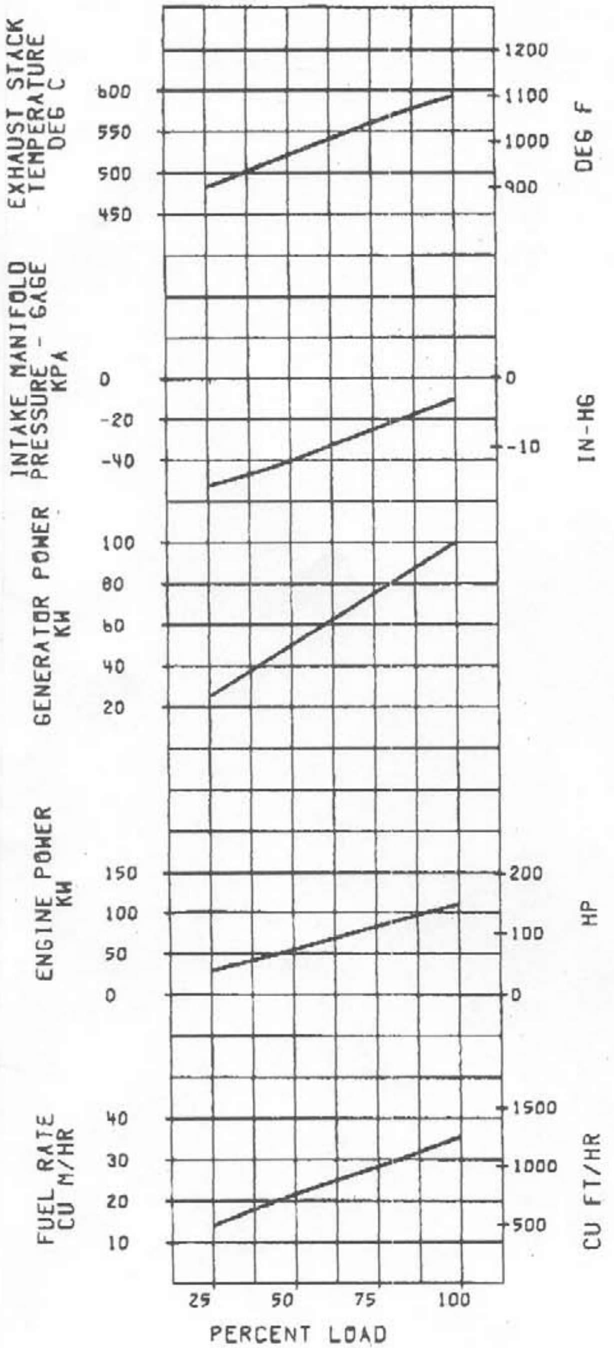


# APPENDIX C

## Appendix C-1. IC Engine Technical Data Sheet

May. 3. 2002 10:20AM MARTIN MACHINERY No. 6435 P. 3

**3306 SI-NA**
**100 kW 60 Hz**




ENGINE DATA

| | |
|---|---|
| ENGINEERING MODEL | E267 |
| ASPIRATION | NA |
| AFTERCOOLER | NONE |
| EXHAUST MANIFOLD | WET |
| COMBUSTION SYSTEM | SI |
| TURBO MODEL | NONE |
| COMPRESSION RATIO | 10.5 TO 1 |
| TYPE OF DUTY | CONTINUOUS |
| RATED KW | 100 |
| RATED HZ | 60 |
| RATED RPM | 1800 |
| EFFECTIVE SERIAL NUM | 7Y00001 |

TOLERANCES

CURVES REPRESENT TYPICAL VALUES BTAINED UNDER NORMAL OPERATING CONDITIONS. AMBIENT AIR CONDITIONS AND FUEL USED WILL AFFECT THESE VALUES. ACH OF THE VALUES MAY VARY IN ACCORDANCE WITH THE FOLLOWING TOLERANCES

| | |
|---|---|
| EXHAUST STACK TEMPERATURE | ±42 DEG C<br>±75 DEG F |
| INTAKE MANIFOLD PRESSURE-GAGE | ±1.7 KPA<br>±0.5 IN-HG |
| POWER | ±3 PERCENT |
| FUEL RATE | ±0.707 MJ/KW-HR<br>±900 BTU/HP-HR |

PERFORMANCE DATA

| PERCENT LOAD | ENGINE POWER KW | ENGINE POWER HP | GEN POWER AT 0.8 PF KW |
|---|---|---|---|
| 100 | 110 | 148 | 100 |
| 75 | 83 | 111 | 75 |
| 50 | 55 | 74 | 50 |
| 25 | 29 | 39 | 25 |

| PERCENT LOAD | BSFC MJ/KW-HR | BSFC BTU/HP-HR | FUEL RATE CU-M/HR | FUEL RATE CU-FT/HR |
|---|---|---|---|---|
| 100 | 10.87 | 7682 | 35.44 | 1252 |
| 75 | 11.50 | 8127 | 28.29 | 1000 |
| 50 | 13.30 | 9399 | 21.68 | 766 |
| 25 | 16.34 | 11548 | 14.05 | 496 |

AIR FLOW AT FULL LOAD

INLET 6.5 CU M/MIN 230 CFM
EXHAUST 19.0 CU M/MIN 670 CFM

CONDITIONS

PERFORMANCE BASED ON SAE J8168 STANDARD CONDITIONS OF 99.2 KPA (29.38 IN HG) AND 30 DEG C (85 DEG F). PERFORMANCE ALSO APPLIES AT DIN 6270 STANDARD CONDITIONS OF 97.8 KPA (28.97 IN HG) AND 20 DEG C (68 DEG F).

FUEL RATE IS BASED ON GAS HAVING A LHV OF 33.74 KJ/LTR (905 BTU/CU FT)

ENGINE POWER CURVE REPRESENTS THE POWER REQUIRED FOR DRIVING A CATERPILLAR GENERATOR USING AN ENGINE EQUIPPED WITH LUBE OIL AND JACKET WATER PUMPS BUT WITHOUT FAN

THE GENERATOR POWER CURVE REPRESENTS THE ELECTRICAL OUTPUT OF THE GENERATOR

STACK TEMPERATURE. INTAKE MANIFOLD PRESSURE AND FUEL RATE ARE BASED ON ENGINE POWER CURVE

NO ENGINE DERATION IS REQUIRED FOR AMBIENT TEMPERATURES UP TO 52 DEG C (125 DEG F) EXCEPT AS SHOWN ON THE APPLICABLE ALTITUDE DERATING CURVE.

| GAS ENGINE GENERATOR SET PERF CURVE | MODEL 3306 | TD0281-04 |
|---|---|---|